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BEFORE THE ARIZONA CORPORATION C

Arizona Corporation Commission
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MARCIA WEEKS
CHAIRMAN
RENZ D. JENNINGS
COMMISSIONER
DALE H. MORGAN
COMMISSIONER

IN THE MATTER OF THE A.A.C. R14-2-704 HEARING FOR INTEGRATED RESOURCE PLANNING.	DOCKET NO. U-0000-93-052 DECISION NO. 58643 **OPINION AND ORDER**

DATES OF HEARING: August 20 and November 22, 1993 (Procedural Conferences), December 7, 8, 9, 10, 13 and 14, 1993

PLACE OF HEARING: Phoenix, Arizona

PRESIDING OFFICER: Bradley S. Carroll

IN ATTENDANCE: Renz D. Jennings, Commissioner
Dale H. Morgan, Commissioner

APPEARANCES:

SNELL & WILMER, by Mr. Thomas L. Mumaw, and Arizona Public Service Legal Department, by Ms. Vicki G. Sandler, on behalf of Arizona Public Service Company;

Mr. David Lamoreaux and Mr. Steven J. Glaser, Tucson Electric Power Company Legal Department, on behalf of Tucson Electric Power Company;

Mr. Craig A. Marks, Senior Counsel, on behalf of Citizens Utilities Company;

JOHNSTON, MAYNARD, GRANT & PARKER, by Mr. Michael M. Grant, on behalf of the Arizona Electric Power Cooperative;

Ms. Diane Evans, Salt River Project Law Department, on behalf of Intervenor Salt River Project Agricultural Improvement and Power District;

Mr. Andrew W. Bettwy, Associate General Counsel on behalf of Intervenor Southwest Gas Corporation;

MEYER, HENDRICKS, VICTOR, OSBORN & MALEDON, by Mr. Bruce E. Meyerson, on behalf of Intervenor Arizona Community Action Association;

BROWN & BAIN, P.A., by Mr. Lex J. Smith on behalf of Intervenor Phelps Dodge Corporation;

Mr. Bruce Driver and Mr. Eric Blank, on behalf of Intervenor Land & Water Fund of the Rockies;

Steve Brittle, President, on behalf of Intervenor Don't Waste Arizona, Inc.;

ELLIS, BAKER & PORTER, LTD., by Mr. Richard L. Sallquist, on behalf of Intervenor Cyprus Mineral Company;

Mr. Lothar M. Schmidt, Intervenor in Propria Persona;

Mr. K. Justin Reidhead, Chief Counsel, on behalf of the Residential Utility Consumer Office; and

Mr. Bradford A. Borman and Ms. Janice M. Alward, Staff Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

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BY THE COMMISSION:

PROCEDURAL HISTORY

Pursuant to A.A.C. R14-2-703.F, Arizona Public Service Company ("APS"), Tucson Electric Power Company ("TEP"), Arizona Electric Power Cooperative ("AEPCO"), and Citizens Utilities Company ("Citizens"), filed with the Arizona Corporation Commission ("Commission") their respective resource plans and related exhibits (collectively referred to herein as "Plans"). APS and TEP filed their Plans on December 31, 1992, AEPCO filed its Plan on February 16, 1993, and Citizens filed its Plan on March 31, 1993. Additionally, on January 29, 1993, Salt River Project Agricultural Improvement and Power District ("SRP") voluntarily filed a Plan. On March 24, 1993, pursuant to A.A.C. R14-2-704.A, the Commission issued Decision No. 58227 which, in part, ordered that a hearing for resource planning be scheduled to commence on or after December 6, 1993. By Procedural Order dated April 12, 1993, the hearing was set to commence on December 7, 1993.

The following parties applied for, and were granted intervention: the Residential Utility Consumer Office ("RUCO"), Southwest Gas Corporation ("SWG"), SRP, Land and Water Fund of the Rockies ("LAW Fund"), Mr. Lothar M. Schmidt, Arizona Community Action, ("ACAA"), Phelps Dodge Corporation, Don't Waste Arizona, Inc.[1], and Cyprus Minerals Company.

Workshops related to this Docket were held on October 8, 18, 19 and 20, 1993 and the hearing commenced on December 7, 1993 before a duly authorized Hearing Officer of the Commission at the Commission's offices in Phoenix, Arizona. At the beginning of the hearing, public

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[1] For this proceeding, Don't Waste Arizona, Inc.'s interests were represented by the LAW Fund.

comment was taken. The hearing was conducted along the following topical lines: load forecasting; administrative matters; demand side management; and supply side issues. At the conclusion of the hearing, the Hearing Officer took the matter under advisement pending submission of a Recommended Opinion and Order to the Commission and the parties were given leave to file closing memoranda in lieu of closing statements.

DISCUSSION

I. Introduction

On October 14, 1988, the Commission issued Decision No. 56180 which adopted rules to implement Integrated Resource Planning ("IRP") in the State of Arizona. On January 12, 1989, the Commission issued Decision No. 56313 which amended the IRP rules. These rules require electric utilities with generating facilities to submit Plans every three years. Pursuant to A.A.C. R14-2-704, the Commission is to determine the degree of consistency between the Plans filed by the utilities and the analysis conducted by Staff, as well as the information provided by other parties. In making its consistency determination, the Commission is to consider, among other things, the following:

- the total cost of electric energy services;
- the degree to which the factors which affect demand, including demand management, have been taken into account;
- the degree to which non-utility supply alternatives, such as cogeneration and self-generation, have been taken into account;
- uncertainty in demand and supply analyses, forecasts, and plans, and the flexibility of plans enabling response to unforeseen changes in supply and demand factors; and
- the reliability of power supplies.

Pursuant to the rules, APS, TEP, AEPCO, and Citizens (collectively referred to hereinafter as the "Companies"), filed with the Commission their respective Plans. Additionally, SRP voluntarily filed a Plan.

The purpose of the IRP process is to minimize the total societal costs of meeting the demand for electric energy services giving due consideration to ratepayer impacts, global competitiveness, utility financial health and economic growth within a utility's service area. This goal can be achieved by finding the mix of supply and demand side resources that minimizes society's costs. Electric utilities, however, are coming under increasing competitive pressure to keep prices to their customers low. Impacts on the competitive position of Arizona's utilities warrant specific consideration in the development and implementation of IRPs. The competitive position of U.S. business in the global marketplace also warrants consideration. This competitiveness depends, in part, on energy efficiency. Notwithstanding the competitive pressures in Arizona, the U.S., and the global marketplace, short-term competitive pressures should not overwhelm the long-term need to have a balanced portfolio of supply and demand resources.

One of Staff's roles in the IRP process is to review the Plans filed by the Companies for consistency under the Commission's rules. Staff conducts its own load forecasts, examines demand side resources, and evaluates alternative supply side resources over the life cycle of the resources, including the comparison of renewable resource technologies with conventional fossil fuel resources. Staff also reviews utility system reliability. The analysis of environmental externalities has not yet begun, but Staff is developing rules based on the recommendations of an externalities task force report prepared during 1992 as a result of the last IRP docket.

II. Demand Side Management

Introduction

Demand side management ("DSM") is the systematic effort to improve the efficiency of using electric energy and power. Examples of DSM are energy efficient lighting, improved building thermal envelopes, reduced standby loss in water heaters, and more efficient electric motors. DSM is cost-effective if reductions in power usage at peak production times for the utility and reductions in energy usage at any time are less costly to society than generating, transmitting, and distributing electricity, including building of any new generation, transmission, or distribution capacity.

The Law Fund[2] has posited three regulatory elements that are necessary to encourage utilities to invest in cost-effective energy efficient programs:

- utility recovery of the costs it incurs to plan, design, implement, and evaluate its DSM programs;
- recovery of the lost net revenue caused by the energy and demand reductions attributed to the utility's DSM programs; and
- a financial incentive for the utility to encourage it to run innovative and aggressive DSM programs.

The major DSM programs currently underway in Arizona are:

- commercial sector lighting programs in which inefficient lighting is replaced by more efficient lamps and ballasts, in which adequate lighting levels are maintained through delamping and installation of reflectors, and in which lighting is controlled by occupancy sensors and dimmers;

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[2] The LAW Fund is a regional environmental organization headquartered in Boulder, Colorado with its membership drawn from the Rocky Mountain and Desert Southwest states. The Energy Project of the LAW Fund is committed to reducing the environmental impacts associated with meeting the need for utility energy services.

- educational programs aimed primarily at school children;
- new home programs aimed at meeting energy-efficient mortgage performance standards for the entire house allowing builders to substitute among efficiency measures to meet the standard;
- residential retrofit programs, currently focused on upgrading the efficiency of heat pumps;
- residential audits including audits by mail and on-site audits;
- tree planting to create shade on sunstruck sides of buildings thereby reducing space cooling needs; and
- replacement of existing motors with energy efficient motors.

The Commission currently has a process for reviewing utility DSM programs in cases where the Commission has established a cost-recovery mechanism. In particular, in order to qualify for cost recovery, Staff must pre-approve each utility program before it is implemented. Staff's pre-approval review looks at societal costs and benefits, program feasibility, the marketing plan, and the monitoring and evaluation plan.

Proposed Type and Level of DSM

In general, the range of DSM programs is expected to expand from current efforts. Utility projections of DSM power savings are about 1160 megawatts ("MW") between 1992 and 2010. Overall, through 2010, additions of DSM are about one quarter of the projected growth in demand (where demand consists of retail demand plus energy services met through DSM.)

At the hearing, the Companies summarized their DSM goals for the present and future. APS indicated that DSM expenditures should not be mandated as a simple proportion of gross revenue. Instead, APS believes that DSM should be pursued to achieve the highest benefit at the lowest cost.

TEP testified that its primary objectives for DSM are achieving peak load reduction and obtaining load factor improvement, while making cost beneficial resource decisions that minimize rate impacts. The TEP 1992 Plan projects 100 MW of new DSM over the next 15 years in addition to the 7 MW already achieved through 1992. TEP testified that this accounts for 22 percent of all the expected resource additions over this period and results in an overall peak reduction of five percent. TEP estimates that annual energy reduction in the year 2007 will be approximately 330 gigawatt hours ("gwh"), representing an overall energy reduction of 3.5 percent.

AEPCO testified that it is committed in the short-term to implementing a variety of new DSM programs to complement its existing DSM activities. AEPCO believes that the magnitude and timing of these programs can be accelerated or scaled back in response to changing economic, social, environmental, and regulatory conditions. Additionally, AEPCO indicated that it can adjust the magnitude and timing of its DSM programs based on feedback regarding the cost and performance of these programs. AEPCO has already taken steps towards implementing the DSM programs identified in its Plan. Its Marketing Task Force has developed commercial lighting, industrial motor, and energy storage programs that have been submitted (as of the date of the hearing) to its Board of Directors for approval.

Many utility programs are technology specific (e.g., a lighting program) and historically, utility programs have emphasized rebates to induce customers to participate. In contrast, Citizens is proposing facility-based programs to implement all cost-effective measures for commercial, industrial, and residential participants. Citizens also plans to use energy service companies ("ESCO") to implement many of its programs and program participants will repay the ESCO for the DSM measures out of their savings. Citizens is also placing a heavy emphasis on using local organizations and trade allies to implement programs rather than having the utility implement the programs.

As a potential addition to the menu of DSM programs offered by the Companies, Staff recommended that the Companies consider a design team approach to new commercial buildings to encourage the construction of energy efficient new buildings. As this recommendation is meritorious and was unopposed, we shall direct the Companies to either develop a design team approach to new commercial buildings to encourage the construction of energy-efficient new buildings, or indicate in their regular reports on DSM programs, why design teams are not appropriate. Staff also recommended that the Commission adopt as a general policy, a requirement that all special contracts which offer discounted rates to attract a business or retain a business include a provision mandating that the customer implement energy efficiency measures if cost-effective to do so.

Staff believes that repayment programs in which program participants repay the utility any incentives out of savings may be successful in lowering the costs to the utility of implementing DSM programs and more equitably distribute the costs of DSM programs in relation to the benefits received. It is, however, currently difficult to determine when success is likely. Staff has proposed that it prepare a background paper based upon experience in other jurisdictions and then conduct a workshop to discuss the paper and to hear presentations by representatives from organizations with experience in repayment programs. We believe that Staff's proposal will educate the Companies and the Commission on repayment programs and we will require Staff to undertake this workshop. The Companies, commercial and industrial customers, and residential consumer organizations should be invited to attend the workshop and should be prepared to discuss the advantages and disadvantages of repayment programs. The LAW Fund's bonus program should also be included as a topic in the workshop.

Several intervenors commented on proposed DSM programs. The LAW Fund raised concerns that the proposed DSM programs primarily reduce peak demand and may not reduce energy consumption and may even increase energy consumption. Staff believes that the major pre-approved DSM programs such as energy-efficient new homes, commercial lighting, efficient motors, and shade trees are likely to save significant amounts of energy and power.

ACAA[3] presented evidence on the advantages of increased energy efficiency programs for Arizona which extend to low-income utility customers. ACAA indicated that the purpose of its testimony was to urge the Commission to:

- approve adequate and cost-effective DSM measures for all utility consumers with a fair and equitable portion of DSM resources devoted to low-income customers;
- establish a collaborative process for the development, implementation, evaluation, and monitoring of all DSM programs; and
- establish alternative DSM delivery mechanisms with specific measures such as lighting, refrigerator replacement, and tree planting.

ACAA believes that the proposed Plans and DSM program packages of both APS and TEP are positive and important steps towards realizing the economic and environmental benefits of IRP and that these companies

[3] ACAA is a statewide private, non-profit organization whose primary concern is helping low-income people become self-sufficient. There are 22 community action programs throughout Arizona.

deserve credit for their good-faith efforts in developing their Plans and programs to pursue energy efficiency as a cost-effective alternative to conventional supply side resources. ACAA also believes that both companies have established important foundations for development of this alternative, and their efforts are not to be discounted. ACAA, however, argued that all major customer classes, regardless of size or type, should have an opportunity to participate in a meaningful and substantive DSM program.

RUCO testified that the Plans fail to analyze the appropriate issues or acknowledge that much of the information needed for effective planning (particularly on the DSM portion of the Plan) is simply not available at this time and needs to be systematically acquired through actual experience from implementation of DSM measures. RUCO indicated that while much hard work and good analysis was performed by the various utility staffs and consultants, the Plans that were filed (except Citizens') fail to provide a useful analysis or plan for the future. RUCO requested that the Commission direct that more measures and programs be screened for cost-effectiveness under a variety of circumstances and conditions. Additionally, RUCO stated that the Commission should direct that the methods used to screen measures or programs, or to select program plans, be consistent with the primary objectives identified by the Commission in its integrated least cost planning process. Further, RUCO recommended, in part, that the Companies should, in consultation with Staff and interested parties, plan and undertake an aggressive effort to:

- learn how to acquire large scale DSM resources successfully and more cost-effectively, while attempting to minimize potential rate impacts. The Companies should test market preparation, market transformation, integrated delivery and program designs in which the participants repay the utility for conservation services on their utility bill;

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- promptly pursue the development and implementation of effective low-income DSM programs by recognizing all of the benefits available from such programs and by increasing the cost-effectiveness of such programs by pursuing joint delivery with other utilities and with weatherization providers;

- pursue the application of innovative and intensive DSM efforts including the use of community-based demonstration projects to try to avoid the need for new transmission capacity in the Anza and Mohave regions.

RUCO also noted that the Commission should not establish a maximum level of achievable DSM potential due to the current lack of information and data to develop a credible estimate of such potential. RUCO, however, believes that the Commission could accept for planning purposes the proposed DSM resource potential estimates presented in the Plans as reasonable at this time.

ACAA believes that the commitment to DSM as a viable, cost-effective energy resource by both APS and TEP needs to be significantly increased. ACAA found that the Companies' DSM budgets and savings targets are low, and each Company's process to analyze, develop and implement DSM programs could be improved to assure that DSM as an energy resource is developed to its full potential. ACAA has recommended that APS should have spending targets of between 2.5 percent and 5 percent of gross operating revenues for DSM. ACAA has also proposed specific dollar levels for DSM programs, well in excess of current levels, recommending an annual budget of $35 to $70 million for APS and an annual budget of $13 to $26 million for TEP.

We agree that larger programs are desirable now that APS and TEP have demonstrated their ability to develop, implement, review, and modify DSM programs. DSM programs should be undertaken as long as the incremental benefits to society exceed the incremental costs to society. It is conceded that many utilities throughout the U.S. have had a much larger commitment to DSM than TEP and APS. In 1989, DSM spending for all U.S. utilities as a percentage of total electric utility revenue was .5 percent; and in 1992, 1.2 percent. No Arizona utility has achieved .5 percent yet. We intend to look at DSM levels closely in rate cases.

At this time, there is, however, insufficient information to determine whether ACAA's levels are appropriate and dollar targets have the drawback of focusing on how fast to spend money rather than how to achieve cost-effective savings. A dollar target can be understood only if the types of DSM programs and delivery mechanisms contemplated are known. Furthermore, it is wise to be cautious concerning the start of too many programs simultaneously because utility staffs may be unable to properly develop, implement, monitor, and evaluate those programs.

We find that the Companies, especially TEP and APS, should expeditiously increase their DSM activities and targets and that these accelerated DSM targets should be included in the next IRP filings. We will not adopt specific targets at this time as we believe that the Companies should have the time and opportunity to first make their own determinations. If, however, the Companies do not accelerate their DSM activities, we shall reconsider specific targets in future IRP hearings which also may include mandates for reaching such targets as proposed by ACAA.[4]

ACAA also proposed specific budget levels for low-income DSM programs of $2.4 to $4.8 million for APS and $885,000 to $1.77 million for TEP. Further, both RUCO and the LAW Fund support the development

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[4] Under this analysis, we will not order APS to implement its IRP Plan 11 (as opposed to IRP Plan 10) as recommended by ACAA.

of more and better designed low-income DSM programs. We support cost-effective DSM for low income households. The specific level, however, will depend on the incremental societal costs and benefits of DSM for low income households and the proper level of activity cannot be determined without some actual experience. For example, ACAA indicates that there are several possible barriers to improved energy-efficiency in low-income housing units such as high hurdle rates, lack of information, lack of capital, and rental status. We shall, therefore, direct the Companies to develop their DSM programs to deal with these kinds of problems.

APS has indicated that it supports a new DSM program for low-income housing and is proposing to submit a specific design to Staff. APS also indicated it would invite ACAA to work with it prior to final design and submittal of the low-income plan. We encourage such cooperation.

Although we will not adopt specific targets for low-income programs at this time, we will direct APS to begin its low-income pilot program with potentially cost-effective DSM measures and then, after one year, modify the program as appropriate. TEP should use the results of its current low-income program to develop a larger, cost-effective low-income DSM program. We believe that DSM programs ought to reflect an equitable division among all customers, including low-income customers.

We also note that the magnitude of DSM activities will affect utility rates. A precise estimate of the rate impacts of large increases in expenditures for DSM for APS and TEP can only be determined in the context of a rate case with details on DSM expenditures, other utility costs, impacts of DSM on kilowatt ("kw") and kilowatt hour ("kwh") sales, impacts of DSM on utility costs, rate design parameters, and other factors.

ACAA has also recommended that the Companies should be directed to consider fuel switching in its future resource mix. We concur with this recommendation and will require the Companies to at least consider in their next IRP filing, whether fuel switching as a DSM resource potential is an option.

Public Input into DSM Programs

The Commission's IRP process offers the opportunity to provide public input into the selection of DSM measures and design of DSM programs. Parties to this Docket have provided important recommendations on how to improve the menu of DSM programs offered by the Companies.

The LAW Fund proposed a fund which would support participation by intervenors in IRP activities. Although we believe that there are some inherent problems with this, such as how to determine whether an intervenor is given money from the fund, the LAW Fund is free to explore this proposal with Staff and other parties at workshops to be held in the future.

Southwest Gas Corporation ("Southwest Gas") is concerned that the current process for review of electric utility IRP Plans is too limited to allow adequate analysis and comment from all intervenors, thereby unduly restricting input the Commission might otherwise be provided. Southwest Gas is also concerned that the Companies may disguise promotional programs as DSM programs. Southwest Gas recommended that the Commission take steps to ensure that adequate information is made public about each Plan to allow review by intervenors and members of the public. It also recommended that an annual reporting process for review of DSM activities should be instituted. In that filing, the Companies should update the status of each DSM program. The filing should then be docketed and be a part of the public record. Finally, the Commission should carefully review the DSM programs of APS to ensure that any promotional activities are removed.

The Companies prepare regular reports for Staff on progress with their DSM programs. It appears that some parties have not found these reports easy to obtain and may have misconstrued the availability of these reports. Southwest Gas states that utility DSM reports "have been filed on a confidential basis and are not available for public inspection." With some minor exceptions, no parts of any utility DSM reports are confidential. Southwest Gas, however, has raised a valid concern regarding availability of DSM reports and the ability of the parties and the public to have more input into the DSM approval process.

To make obtaining the reports easier, we shall require each utility to file one copy of its DSM reports with the Commission's Docket Control for better public access. We also believe that the current procedure for Staff pre-approval of utility DSM programs for which recovery is sought, does not permit sufficient opportunity for interested parties (such as RUCO, competitors, and other intervenors) to have direct input prior to Staff approval. Further, although interested parties may have the opportunity to challenge the approval at the utility's next general rate case by arguing that the program is promotional or deleterious, we recognize that there is an inherent unfairness due to the pre-approval itself, as well as a utility's ability to do what Southwest Gas has termed as "distort the market."

Although we do not necessarily agree that there has been, or will be, a distortion of the market, we shall require any utility that files a DSM program for Staff pre-approval for recovery, to file a notice of such filing and a copy of such plan with the Commission's Docket Control and notify all interested parties[5] of the filing. The interested parties shall then have 20 days to file any written comments with Staff so that Staff may take such comments into consideration before granting or denying pre-approval. Upon Staff's pre-approval, Staff should submit the projects to the Commission for its consideration and preliminary adoption. If the Commission adopts the pre-approval, the projects should be considered approved for cost-recovery in future rate proceedings. The Commission, however, reserves the right to review the projects in future rate proceedings, if necessary, to make a final determination with respect to the appropriateness of the cost-recovery.

The LAW Fund recommends that the Commission ask the Companies to establish a DSM collaborative process to prepare Plans to address three inter-related issues:

- the scope of an expanded commitment to DSM;
- changes in Commission regulation to encourage Arizona utilities to acquire all cost-effective DSM over the long-run; and
- measures to address or mitigate adverse rate impacts associated with an expanded and sustained utility commitment to DSM.

Under the LAW Fund's proposal, the resulting Plans would be presented to the Commission for review and approval.

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[5] Interested parties shall include RUCO, all parties to the utility's last rate case, all parties to the last IRP proceeding, and any other interested party that makes itself known to the utility such as through workshops.

The Companies expressed concerns regarding the collaborative process as proposed by the LAW Fund and supported by ACAA. APS (for example) was concerned that the collaborative process would seek to replace the utility's management with an ad hoc committee of parties having neither final responsibility for the success or failure of its DSM programs nor the intimate knowledge of the APS system of management. Further, APS was concerned that the process would diminish the role of the Commission and Staff by limiting the involvement of the Commission to that of a mere dispute arbitrator and of Staff, to just one of many co-equal participants in the collaborative process.

Staff recommended that within twelve months from the Commission's Decision in each IRP proceeding, each utility solicit from parties to this Docket (and other interested parties who make themselves known to the utility and to Staff) specific proposals for DSM measures, programs, and screening prior to preparing its Plan for the next required filing, and that workshops on DSM proposals should be held. Staff has indicated its willingness to help coordinate these workshops as necessary.

We find that the proposed workshops on DSM activities would promote greater public participation in the DSM planning process without removing from the Companies their responsibilities to develop and implement DSM programs and without removing from Staff its responsibilities to review those programs. We believe this to be a more reasonable approach than the proposed collaborative process since the workshops provide all interested parties the opportunity for input, while keeping ultimate planning and decision making authority with the Companies and the Commission. Staff shall, therefore, coordinate one set of workshops between IRP filings for the purpose of obtaining input from the public on DSM plans. The Companies should provide all parties with written material prior to the workshops describing DSM screening criteria and DSM plans. Likewise, to make the workshops more productive, all parties should provide the Companies and each other with written proposals or comments prior to the workshops. The workshops should be used to explore the possibility of an agreement between the Companies and other parties on DSM plans and screening criteria. If agreements are reached, they can be noted in subsequent Plans.

Monitoring and Evaluation ("M&E") of DSM

The Companies have not completed the monitoring of savings from their pre-approved DSM programs. Savings based on engineering estimates for the largest programs in 1992 were presented by Staff in its Staff Report. Engineering estimates may be in error because customer behavior may alter the expected performance of the measure and because on-site conditions may vary from those assumed in making the engineering estimate. Thus, the savings estimates are to be considered as preliminary and monitoring results may be different.

Utility progress on program M&E is hard to judge since monitoring efforts are still underway. However, there seems to be varied attention paid to the importance of assessing how well a program is working in the field. Staff has recommended that the Companies give the highest priority to M&E, including evaluation of kw and kwh savings and process evaluation in their DSM efforts. We concur with this as a general policy and will outline specific requirements hereinbelow.

RUCO agreed with Staff that the Commission should require greater efforts in improving M&E capabilities. RUCO, however, was concerned that there is a danger that M&E could overshadow and distort the very purpose of DSM. RUCO presented testimony that:

> M&E should be seen as a useful tool to inform decision makers, not an end unto itself. While M&E is crucial, it should not dictate the types of programs or technologies offered by the utilities. A strong focus on evaluation should not result in utilities only offering programs that are easy to measure. M&E should be used to provide information about DSM programs and resources, not as a barrier to the development of effective programs.

RUCO has recommended that the Commission direct the Companies to focus their M&E efforts on:

- assessing net program effects (net savings);
- assessing and reducing ratepayer risks (determining the persistence and reliability of DSM resources); and
- improving their DSM program and delivery.

RUCO believes that generating public confidence in M&E capabilities is a goal that the Companies and the Commission should strive to achieve.

Staff concluded that evaluation of kw and kwh savings should be conducted using state-of-the-art methods in a competent, scientific manner. The data and results should provide a comprehensive, internally consistent account of the savings from DSM. Often, the question of savings must be examined using two or three different methods or databases because of uncertainty about baseline conditions and wide confidence intervals around statistical results. There are numerous techniques which can be used depending on the data, the type of participants, and other factors. Staff's review of utility evaluations of DSM savings is expected to be a scientific review process in which Staff conducts its own analyses to test the validity of the Companies' findings and in which Staff compares utility results with results from other studies. Staff does not wish to develop rigid guidelines that unduly constrain research in a rapidly developing field. We concur with this approach, and encourage the parties to coordinate M&E guidelines in the cooperative efforts described below.

Advertising appears to be growing in importance as a cost element of DSM programs. Staff concluded that advertising should be carefully monitored by the utility to determine, at a minimum:

- whether the mix of advertising and other program elements (such as rebates or personal sales calls) is optimal;
- how much advertising has changed consumer behavior;
- whether advertising is well targeted;
- whether the information content is appropriate;
- how advertising supports other elements of the marketing plan such as personal calls to building energy managers; and
- how the advertising effort should change as the program matures.

Staff recommended that the Companies include in the pre-approval packet a monitoring plan for advertising for each DSM program whose advertising costs are budgeted to exceed $100,000 per year.

Staff also recommended that the Companies give greater emphasis to measuring the impact of free ridership and free drivers on the level of savings associated with their DSM programs.[6] We recognize the difficulties of analyzing free ridership and free drivers. Nonetheless, this is an important issue in M&E and must be confronted. We shall, therefore, require that the Companies measure the impact of free ridership and free drivers on the level of savings associated with their DSM programs in cases where such effects are likely to be

[6] "Free riders" are program participants who would have undertaken the DSM measures without the DSM program and "free drivers" are nonparticipants in the DSM program who undertook DSM because of the existence of the program.

important and significantly influence the cost-effectiveness of a DSM program.

Southwest Gas, ACAA, RUCO, and the LAW Fund indicated that they would like to see a public or collaborative process for reviewing, among other things, the M&E of the Companies' DSM programs. We agree that the review of M&E of DSM should be a public process. However, pre-approval of DSM projects should remain a Staff responsibility. A public process will ensure that study designs take into account relevant factors and that inferences from the analysis are reasonable. Staff proposes that APS, TEP, AEPCO, and Citizens each make an annual presentation at workshops covering the following topics:

- study designs for DSM programs for which monitoring is required (as indicated in Staff's pre-approval letter) and for which monitoring has not yet begun or is about to begin (including process evaluations);
- progress reports on M&E projects underway (including process evaluations); and
- results from M&E projects that have been completed during the previous year or are near completion (including process evaluations).

We find that the proposed workshops, as well as the above requirement of notification of pre-approval filings, will improve public participation and enhance the Companies' M&E efforts. We shall, therefore, require Staff to set up appropriate workshops once a year to address M&E. The Companies should present estimates of kw and kwh savings and describe process evaluations, as well as provide copies of study plans, reports, and handouts in advance of the workshops. We expect other parties to actively participate in the workshops and provide constructive suggestions.

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Financial Disincentives to DSM

Financial barriers to DSM have led the Commission to develop mechanisms for program cost-recovery, recovery of lost net revenues, and recovery of a profit or reward to make the utility indifferent between traditional supply side resources and DSM. According to Staff, relative to traditional regulation, a DSM program should ensure timely recovery of program costs, and a return equivalent to what the utility would have received from regulatory lag (increased sales between rate cases minus variable costs, i.e. net revenues) and from ratebasing future generating, transmission, and distribution capacity that will be deferred or avoided as a result of DSM.

Staff concluded that the Companies will need incentives to engage in DSM (beyond early pilot efforts) such as recovery of program costs, lost net revenues, and perhaps a profit or reward. Staff concluded that the Commission should continue on a case-by-case basis, in the context of a rate case, to design appropriate incentives. RUCO recommended that the Commission convene a working group of the Companies, Commission Staff and other interested parties to perform a thorough review of the potential regulatory disincentives (or need for positive incentives) for increased DSM resource acquisition. In particular, RUCO recommended that the issues of program cost recovery, lost net revenues, and financial incentives should be addressed. The LAW Fund indicated that current utility regulation:

- rewards shareholders for higher load growth regardless of the benefits that customers enjoy from this greater electricity use;
- penalizes shareholders for DSM programs that promote customer energy-efficiency regardless of the economic and environmental benefits such programs provide; and
- penalizes shareholders for energy-efficiency programs.

Several intervenors focused on mechanisms to remove financial barriers to additional DSM activity. ACAA stated that if there is a significant time lag between the implementation of a DSM program and the next rate case, then the Companies should be granted deferral accounting authority or be allowed to establish a balancing account for recovery of costs at the time of the next rate case. The LAW Fund proposed a collaborative process for at least APS to develop a package of reforms that makes it financially possible for the Companies to engage in large scale DSM.[7] The LAW Fund proposed that the Commission set up this collaborative process (primarily for just APS) over the next 3 to 6 months to examine how to remove financial disincentives to the Companies from engaging in DSM and to address short-term concerns about the effects of DSM on electricity rates. A similar proposal for a collaborative approach to compensating the utility for DSM was raised by RUCO. Finally, the LAW Fund expressed concern about the effects of the existing cap on APS' DSM cost recovery.

We believe that it is important for the Companies to be fairly confident of recovering their prudent costs of DSM in order to encourage them to engage in large scale DSM programs. Based upon the evidence presented in this proceeding, recovery of program costs and lost net revenues and possibly a reward or profit for DSM, should be considered, recognizing that preferences for a particular recovery mechanism vary among the parties.

As of the commencement of the hearing, APS has a $4 million annual cap in place on recovery of DSM costs. The cap was created because of the uncertainty about APS' ability to implement DSM

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[7] It is also intended to limit the impact of this on nonparticipants, an issue that motivates the Law Fund's proposed bonus program.

programs and because it was expected that APS would file a rate case in which the cap could be modified or eliminated more quickly than is turning out to be the case. APS testified that all costs of approved DSM programs, including net lost revenues, should be recovered through the APS Energy Efficiency and Solar Energy Fund ("EEASE Fund)" approved by the Commission in Decision No. 57649 (December 6, 1991). Although a cost deferral mechanism recognizes the DSM expenditures for future recovery, the timely recovery of program costs, lost net revenues and incentives, provides a more appropriate form of regulatory treatment for DSM. Finally, in TEP's recent rate case, cost recovery was limited in magnitude by TEP's plans as of the time of the rate case hearing.

Although RUCO and the LAW Fund propose a collaborative approach to removing disincentives to DSM, it is not clear that TEP and APS are holding back on DSM because they need additional incentives. Rather, any financial disincentives are more likely attributable to the limitations on cost recovery imposed during rate cases and potential impacts of DSM on rates. Staff has recommended a deferral account approach for APS and TEP to accommodate much larger DSM efforts by these companies.

To encourage APS and TEP to significantly enlarge their respective DSM programs, we shall adopt a deferred accounting approach as described below. The Companies desiring deferred accounting must file for Commission approval.[8] We direct the Companies to include the

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[8] Any utility may make an application for a deferred accounting order. At this time, AEPCO has no cap on DSM programs and Citizens already has a deferral account. However, Citizens may wish to propose modifying its account to include lost net revenues.

following essential elements in their applications for a deferred accounting order:

- A DSM savings target;
- A specific DSM program consisting of cost-effective DSM measures;
- An effective M&E plan; and
- A program designed to manage revenue impacts to the utility and hence ratepayers.

If any of these essential elements is deficient in the Companies' filing, no deferred accounting order will be granted.

It would be useful for parties to this proceeding to meet publicly in workshops with APS and TEP (prior to the utility filing for Commission approval of specific accounting authority) to discuss how the deferral account would work and to consider the rate impacts of the proposed level of deferrals. We direct Staff to set up such workshops and coordinate participation by the Companies. For costs in excess of those included in base rates or existing capped surcharges, deferred accounting is appropriate if ratepayers have a reasonable probability of getting the savings DSM programs can provide. The public review of DSM M&E described above will provide a procedure to establish that assurance.

Costs to be included in the deferral account are program costs (e.g., administrative costs, rebates, M&E costs, and the like) and lost net revenues (if authorized)[9] and, if already authorized, a reward for deferring the return on capacity additions deferred by DSM. Costs may only be entered into the deferral account if they are associated with programs pre-approved by Staff and when kw and kwh

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[9] APS already has authority to recover lost net revenues and the Commission authorized recovery of lost net revenues in TEP's recent rate case.

savings are reasonably probable and can be analyzed and measured using monitored data[10] (following a public review of the analysis in the annual workshops on M&E described above.)

Additionally, program costs may be entered in the deferral account if they are associated with monitored pre-approved educational or research programs from which no kw or kwh savings can be practically derived. The term "monitored" refers to both analysis of kw and kwh savings and process evaluations. Finally, costs included in the deferral account may be recovered at the next rate case, possibly amortized over several years because of their potentially large magnitude. Consistent with Decision No. 57589, deferred amounts may accrue interest at the approved cost of capital of the utility.

As an alternative to the recovery of lost net revenues, the LAW Fund proposed a form of decoupling, called statistical recoupling. In particular, decoupling was proposed by the LAW Fund and is discussed in the Staff Report as a means to unlink utility revenues and sales, thereby removing incentives for utilities to sell more electricity and remove disincentives to engage in DSM. Decoupling can, if properly done, remove the incentive to sell more electricity between rate cases. We leave the door open to all innovative ideas on how to unlink revenues and sales and expect the parties to offer suggestions on this topic in future IRP proceedings.

In light of the above, the Commission shall consider incentives for DSM that focus on recovery of program costs, recovery of lost net

[10] If the M&E indicates that a pre-approved program is not turning out to be cost-effective or that a pre-approved program should be significantly modified, costs up to the time that the M&E was completed should be included in the deferral account. For deferral of costs incurred after that time, the utility should make appropriate modifications in the program (assuming the program is not terminated.)

revenues, and, if appropriate, recovery of a reward for deferring returns on future capacity. As appropriate, the Commission will also consider other means of addressing the incentives to sell more energy and the disincentives to DSM.

DSM and The Energy Policy Act of 1992

Section 111 of the Energy Policy Act of 1992 pertains to IRP and DSM. In particular, several standards are added to the Public Utility Regulatory Policies Act of 1978 ("PURPA"), 16 U.S.C. §2621(d):

> (7) Each electric utility shall employ integrated resource planning.[11] All plans or filings [before the Commission] ... must be updated on a regular basis, must provide the opportunity for public participation and comment, and contain a requirement that the plan be implemented; and
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> (8) The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency resources, and other demand side management measures are at least as profitable, giving appropriate consideration to income lost from reduced sales due to investments in and expenditures for conservation and efficiency, as its investments in and expenditures for the construction of new generation, transmission, and distribution equipment;[12] ... energy conservation, energy

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[11] PURPA defines IRP as "... a planning and selection process for new energy resources that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to its electric customers at the lowest system cost. The process shall take into account necessary features for system operation, such as diversity, reliability, dispatchability, and other factors of risk; shall take into account the ability to verify energy savings achieved through energy conservation and efficiency and the projected durability of such savings measures over time; and shall treat demand and supply resources on a consistent and integrated basis." 16 U.S.C. §2602 (19). The term system cost "... means all direct and quantifiable net costs for an energy resource over its available life, including the cost of production, distribution, transportation, utilization, waste management, and environmental compliance." 16 U.S.C. §2602(20).

[12] PURPA also states that "[t]he rates charged by any electric utility shall be such that the utility is encouraged to make investments in, and expenditures for, all cost-effective

efficiency resources and other demand side management measures shall be appropriately monitored and evaluated.

PURPA requires state utility regulators to consider the standards indicated in 16 U.S.C. 2621(d) and determine whether each is appropriate to implement. PURPA also requires state utility regulators to commence consideration of the standards within two years of October 23, 1992 and to complete the consideration within three years (16 U.S.C. §2622 (b)).

We have considered the standards listed above through the Commission's IRP rules (A.A.C. R14-2-701 et seq.) which have been in effect since 1989 and through rate case decisions cited in Section D, Table 10 of the Staff Report. With respect to making DSM as profitable as investments in capacity, we find that the Commission has initiated efforts in this direction as discussed above.

ACAA proposes that the Commission modify its IRP rules to direct the implementation of Plans as approved, modified or rejected, because it believes that without such action, there is a danger of the IRP process becoming simply informational. We agree that we do not want just an informational process. We are, however, reluctant at this time to institute an approval process for Plans because doing so may limit future Commission review of utility actions in rate cases and other forums. We find that formal Commission approval of a Plan is not necessary for its implementation. IRP is a dynamic process and, as a result of the hearings in this Docket, the Commission has the opportunity to shift the direction of Plans. Second, even without a

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improvements in the energy efficiency of power generation, transmission, and distribution.... State regulatory authorities ... shall consider the disincentives caused by existing ratemaking policies and practices, and consider incentives that would encourage better maintenance, and investment in more efficient power generation, transmission and distribution equipment."

formal approval process, we have seen progress on DSM as a result of the previous Commission decision on IRP (Decision No. 57589). As filed, the Companies' Plans may not fully and properly evaluate either DSM or renewables. However, the Commission can and does rectify any deficiency by ordering the Companies to implement those intervenor and Staff recommendations it finds appropriate. We find that implementation of the Plans is an inherent requirement of the filing under the rules, as well as under the decisions that arise thereunder.

DSM and Clean Air Act Amendments of 1990

Under the Clean Air Act Amendments of 1990, Section 404(f), the Environmental Protection Agency ("EPA") allocates allowances for sulfur dioxide emissions on a first-come, first-served basis to electric utilities who avoid emissions of sulfur dioxide via cost-effective conservation measures or renewable energy sources. 42 U.S.C. §7651c(f). There is to be a Conservation and Renewable Energy Reserve consisting of 300,000 such allowances, each allowing the utility to emit one ton of sulfur dioxide. A utility may use the allowance itself or sell it to another utility. Allowances for conservation and renewable energy are to be allocated on the basis of kwh saved by conservation or generated by renewable energy after January 1, 1992 and before December 31, 2000.[13]

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[13] The value of allowances is still unclear because sales of allowances have been limited to date. In early 1993, the EPA auctioned 150,000 allowances (as authorized in 40 CFR 73.70.) Prices paid for allowances usable in 1995 averaged about $157 and ranged from $131 to $450, and prices paid for allowances usable in 2000 average about $136 and ranged from $122 to $310. Data from "The Energy Report", April 5, 1993, pp. 203 - 205.

To be eligible for these allowances, the electric utility must own or operate at least one affected unit,[14] and must adopt and implement a least cost energy conservation and electric power plan which evaluates supply and demand side resources, including renewable resources. The plan must be approved or accepted by appropriate state utility regulators. For DSM measures, the Secretary of Energy must certify that the state regulator has established rates and charges which ensure that the net income of the utility after implementation of DSM is at least as high as the net income would have been if the energy conservation measures had not been implemented. The Clean Air Act Amendments also require that the Commission approve utility applications for these allowances.

According to 40 CFR 73.82 (58 Federal Register 3696, January 11, 1993), the Commission must approve or accept[15] the utility's least cost plan or least cost planning process and certify that the least cost plan or planning process meets the following requirements:

- provides an opportunity for public participation;
- evaluates a full range of existing and incremental resources to meet demand at lowest cost;
- treats DSM and supply resources on a consistent and integrated basis;
- considers system diversity, reliability and other risk factors; and

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[14] An "affected unit" is a generating unit subject to emission reduction requirements or limitations of the Clean Air Act Amendments. 42 U.S.C. §7651a(2). A list of affected units may be found in 56 Federal Register 63153 et seq., December 3, 1991.

[15] The term "accept" follows from EPA's recognition that "... some State regulatory authorities are unwilling to approve a utility's least cost plan out of concern that such approval will tie the hands of future State regulatory bodies. However, these State authorities will 'accept' a least cost plan if it complies with the State regulatory authority's requirements" (58 Federal Register 3621, January 11, 1993).

♦ is being implemented to the maximum extent practicable.[16]

We find that the Commission's IRP process incorporates these features and meets the criteria for obtaining allowances. We find, therefore that our IRP process meets the requirements of 40 CFR 73.82 (a)(4) and (a)(6) regarding allowances from the Conservation and Renewable Energy Reserve.[17] Additionally, we shall consider the benefits to Arizona utilities with regard to gaining additional sulfur dioxide allowances when determining, in rate cases, whether to allow the utility to recover lost net revenues or rewards for DSM savings.

Miscellaneous

SRP raised a concern regarding Staff's conclusion in its Staff Report regarding high efficiency HVAC programs. Staff concluded that "given current costs, increasing the SEER of air conditioners or heat pumps by itself is likely to be only marginally cost-effective, at best." SRP disputes this conclusion. SRP has a high efficiency HVAC program among its DSM options and is concerned with the implication that the Commission would not allow the Companies to recover such program costs. There is nothing that precludes a utility for filing for approval for recovery of a high efficiency HVAC program. We are making no determination herein with respect to whether such approval should be given. Each program will still be considered on a case-by-case basis.

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[16] The plan or planning process may take into account other factors such as environmental costs and benefits or social factors.

[17] The Commission must also certify that the DSM measures for which allowances are sought are consistent with the least cost plan or planning process (40 CFR 73.82 (a)(5)). This would be done on a case-by-case basis for each application.

III. Supply Side Issues

Introduction

Supply side issues generally relate to an electric utility's ability to supply electricity to its customers (from conventional and unconventional sources and from purchases), and the transmission and distribution of electricity to end-users. Between 1993 and 2010, the Companies plan to add about 2285 MW of new generating capacity at a cost (present value) of $812 million. The first unit to be added is a 75 MW gas-fired combustion turbine to serve Citizens, starting in 1996. Most of the planned capacity to be added between 1993 and 2010 is gas-fired. Combined cycle units comprise nearly half of the planned additions, combustion turbines account for about 25 percent of the new capacity, baseload units comprise 15 percent of the new capacity, and the remainder consists of increasing the capacity of existing plants (uprating) and the use of other technologies, including 10 MW of photovoltaics and 2 MW of fuel cell production.

Staff and the Law Fund believe that it is necessary for the Companies to increase their level of commitment to renewable resources. Staff and the LAW Fund raised concerns that the Companies have not given due consideration to the possibility of significantly higher natural gas prices over the lifetimes of the proposed new generating plants and that the Companies have not planned to hedge their bets on future power plant technologies by diversifying their resource choices. Staff concluded that the potential for large real (inflation adjusted) price increases for natural gas is sufficient to warrant serious consideration of renewable resources; especially solar thermal resources.

The LAW Fund presented evidence that integration of cost-effective DSM and renewable resources into the Companies' IRPs on a sustainable basis will lower utility costs of service, thereby freeing dollars that would otherwise be invested in meeting the demand for utility energy services for investment elsewhere in the economy. The LAW Fund believes that integration of DSM and renewables in IRPs also introduces greater resource diversity into Arizona utility resources, thereby buffering ratepayers against the volatility of fossil fuel prices. Additionally, the LAW Fund testified that DSM and renewables emit no or little oxides of carbon, sulfur, nitrogen, and little or no particulate matter or air toxins, all of which are implicated in such problems as regional visibility degradation, acid rain, global climate change and impacts on human health and terrestrial ecosystems. The LAW Fund has also taken the position that increasing the reliance of the Companies on DSM and renewables will place Arizona on the road toward sustainability in its use of resources to meet the demand for utility energy services.

Although gas-fired resources may be economical under the Companies' base case economic assumptions, the evidence in this proceeding demonstrates that gas prices can vary significantly. Natural gas prices, now at extremely low levels by recent historical standards, could be affected by a number of factors thereby raising utility costs and rates.

In contrast to the price risks associated with natural gas plants, once established, renewable resources[18] are not subject to

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[18] Common forms of renewable energy resources include: photovoltaics; solar thermal resources such as parabolic troughs, parabolic dishes, and central receivers; windpower; biomass consisting of wood, wood waste, agricultural waste, municipal solid waste, and landfill and digester gas; geothermal resources,

these uncertainties. These renewable resource technologies are powered by energy sources which are not affected by market pressures. While such renewable resource technologies do have some operating and maintenance costs, these costs tend to remain stable or increase only gradually over time. In contrast, fuel prices can change dramatically and unpredictably in a short time. Increasing the share of solar and other renewable resource technologies in a utility's portfolio of resources provides a hedge against the risk that the costs of fossil fueled power plants will be increased substantially by forces outside the control of the utility. A diversified resource portfolio containing increasing amounts of solar and other renewable resources will thus protect consumers from facing electricity production costs which are significantly higher than expected. At the same time, it should be acknowledged that the reduction in risk could result in overall higher costs.

Renewables can also have benefits as a hedge against the environmental risks associated with running existing units. The Companies currently rely on coal and nuclear plants to meet the overwhelming majority of Arizona's energy needs. Although these plants are currently relatively inexpensive to operate, future regulatory changes could significantly alter this situation. For example, efforts to deal with global climate change or other unresolved environmental problems associated with coal could significantly increase the costs of operating coal plants. Similarly, the changes in the regulatory environment dealing with the disposal of nuclear waste could also raise the cost of running the Arizona nuclear

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including hydrothermal resources and hot dry rock; and hydropower.

units. Again, renewable resources could provide a partial hedge against these environmental risks.

Based upon the Plans that were filed, it is necessary for the Companies to increase their level of commitment to renewable resources in the manner set forth hereinbelow. There is, however, disagreement with respect to how this is to be achieved. The following analysis deals with the major issues discussed at the hearing.

Renewables Working Group

Staff proposed a joint evaluation of renewable technologies using decision analysis in which a working group of Staff and other parties to the IRP docket would pursue several objectives:

- to develop a better understanding of how to evaluate the risks and benefits of gas-fired plants and renewable resources (with emphasis on solar thermal plants and possibly windpower), by inviting experts on decision analysis, solar and wind technology, and conventional technology to make presentations;
- to collaboratively develop a decision analysis of a generic combined cycle unit, a generic solar plant, and possibly a generic wind plant for the purpose of improving the parties' understanding of how to do such an analysis; and
- to collaboratively develop suggestions on how utilities should analyze the risks and benefits of renewables and conventional technology in their next Plans.

Staff proposed that it chair the working group and that the working group should plan to complete its work within one year from the effective date of this Decision. The product would be a discussion paper on the application of decision analysis to renewable and conventional resource options.

Because of the important technical issues involved, we believe that a working group consisting of Staff and utility planners (as well as any other parties to this Docket who wish to participate) should be created to develop a framework (or frameworks) to thoughtfully handle uncertainty in supply side IRP decisions, to accomplish the three goals listed by Staff, and to complete a discussion paper within one year. Staff should coordinate the working group's activities. Details of the procedures used by the working group should be determined by the participants at the beginning of the process and the working group should determine the range of analytical methods to be explored.[19] We envision that the working group's effort will be primarily educational.

Long-Term Set Asides

Staff recommended "flexible", long-term, set asides[20] for renewable resources of 40 MW each for AEPCO and Citizens, and set asides of 160 MW each for TEP and APS, all to be added by 2009. A set aside is an amount of capacity using renewable resources which must be added by the utility by a given date, subject to the flexibility condition noted below. Staff argued that the set asides provide a signal to the Companies that renewables are important and that

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[19] The working group should strive to focus its activities on productive methods of decision analysis such as by isolating key variables, quantifying those variables using expert opinion and the literature, estimating cumulative probability distributions from expert opinion and the literature on the chances that the variables will exhibit various values, and identifying the strategies which will produce the lowest expected costs. The applicability of sensitivity and scenario analyses can be determined by the working group.

[20] Staff recommends that nameplate capacity be used to determine the quantity of renewables in place. In footnote 24 (page E-26) of the Staff Report, Staff indicated that the capacity of renewables should be determined in terms of the equivalent amount of combustion turbine or combined cycle capacity. This recommendation inappropriately focused on replacing intermediate and combined cycle capacity with renewables capacity. During the course of the hearing, two problems with this approach surfaced: a) renewables may be used for purposes other than supplanting central station generation, as stated by Staff witnesses; and b) it may be administratively complex to determine equivalent capacities for a variety of technologies, since a different analysis would have to be conducted for each technology in each of its potential applications.

research, development, commercialization, and implementation of renewables are not expendable at the first sign of short-term company financial problems.

The LAW Fund also supported the use of set asides coupled with a request for proposals for suppliers of renewable resources to install and possibly operate those resources for the Companies as a mechanism to achieve the set asides. In particular, the LAW Fund proposed that the Companies issue RFPs to obtain 250 GWH per year of renewable energy to be in service between 1998 and 2001. According to Staff, this proposal would mean about 80 MW of renewable capacity in the short-term.[21]

Staff's argument supporting the need for flexible set asides included the following factors:

- in the face of the potentially large increases in the price of natural gas, a portfolio of new peaking and intermediate resources consisting only of natural gas-fired resources is a poor bet;
- a utility commitment to a gas-fired resource coming on line around 2010 will require gas purchases well into the mid-21st century when gas prices and availability are unknown;
- the contribution of renewables should be large enough to significantly hedge the utility's bet that gas will be the cheapest generation source;
- the amount of renewables capacity should not exceed the amount of intermediate and peaking capacity additions planned by the utility; renewables may be best suited as peaking and intermediate resources. The set aside is about one fourth of planned intermediate and peaking additions over the period 1993 to 2009;
- the contribution to a single utility by renewables can be met through a variety of technologies and requires only a modest number of projects of moderate size, such as photovoltaics in a few distribution system sites, one solar thermal central receiver plant, one or more wind project

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[21] We view the LAW Fund's proposal as a stepping stone or intermediate goal between Staff's long-term and short-term set aside recommendations.

sites, and several distributed or central dish/Stirling projects;

- the Companies should undertake extensive research and development activities with regard to renewables to better define costs and performance characteristics and to encourage the commercialization of renewables at costs lower than today's costs;

- the contribution of renewables should be large enough to cause the Companies to order enough renewable technology so that manufacturers of renewables can gain economies of scale in production and attract investors, thereby causing the price to come down for future buyers. The Companies will be doing this at the same time that utilities in other states are doing the same thing. Therefore, many utilities will be contributing to the process of reducing costs and promoting commercialization of renewable technology;

- the contribution of renewables should be large enough to enable the utility to gain useful experience in commercial scale applications of renewables;

- the timing of the set aside is such that, with active research and development activities by the Companies and others, commercial scale applications of solar thermal technologies are expected to be available at costs lower than today's costs; and

- weak participation by the Companies in research, development, and commercialization of renewables will only delay the commercial availability of economic renewable technologies, thereby costing consumers more than necessary in high fuel prices.

Staff proposes that the Companies could obtain the proposed renewable capacity by constructing and owning their own renewable resource facilities, sharing facilities among several utilities, requesting bids from others to construct and operate renewable resource plants, and assisting customers to install and operate renewable energy technologies at the customers' sites to generate electricity directly for customer use. Short-term set asides (described hereinbelow) may be used by the Companies to count toward the long-term targets described above. Also, because IRP is a dynamic activity, Staff argued that the set asides may have to be revised on a regular basis to reflect fuel cost changes, changes in the costs of renewables, changes in load forecasts, changes in the need for additional capacity, and other factors.

The proposed long-term set asides generated much controversy and testimony. Citizens, APS, TEP, and SRP believe that the Staff proposal for set asides is premature and that additional study is needed before committing to renewables. APS stated that "any commitment to a large 'set aside' for renewables is at best premature and would be ... analogous to the Commission agreeing to buy something without knowing the price, either for what is being bought or for alternatives." Citizens stated that, "given the acknowledged need for additional discussion, a proposal to obligate millions of dollars of incremental capital costs (to renewables) is a premature leap-of-faith."

The Companies also expressed concern that committing to rigid set asides may ultimately turn out to be needlessly costly because the set aside capacities are too large (or too small) or because conditions such as load forecasts or generation costs may be far different than what was planned 15 years earlier, and that blindly adhering to a rigid set aside long after it has become economically stale would counter the aim of resource planning. AEPCO argued that mandatory set asides of renewable resources violate principles of least-cost planning, create a commitment to renewables that is premature, impair the competitive position of AEPCO, undermine system reliability,[22]

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[22] AEPCO also indicated other concerns such as the seasonable variation of power from wind turbines and photovoltaic resources combined with their lack of dispatchability would strain the operation of AEPCO's generation system.

make Rural Electrification Administration ("REA") financing uncertain,[23] and are inequitably large.[24] Similar arguments were put forth by the other Companies.

Further, the Companies argued that Staff's recommendation for long-term set asides was analogous to its recommendation in the last IRP proceeding wherein Staff recommended the adoption of a rebuttable presumption that future construction of intermediate and peaking power plants should be solar thermal power. The Commission rejected this recommendation on the basis (in part) that there was not sufficient evidence to support one industry (solar) enjoying the proposed rebuttable presumption over all other industries. Although there are similarities, we do not agree that the recommendation of long-term set asides is totally analogous to the solar power recommendation.

We find that the time is ripe for serious consideration of renewables over the long run, well beyond the efforts described in the Companies' Plans. Further, we find that it may be necessary to hedge society's bets on future fuel costs by planning for an increased amount of renewables in the utility's portfolios of resources. We also find that it is necessary that when the time comes to commit to new central station generation plants, the Companies will have the knowledge to select, install, and operate renewables and will have ordered enough renewables from suppliers so that the capital costs of renewables decline from today's levels. We are cognizant of the

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[23] Financing for construction of new generating units is currently obtained in conjunction with guarantees provided by the REA. The REA requires the submission of a least-cost plan as part of any application for funding.

[24] While 40 MW may be 25 percent of the identified generation additions in AEPCO's 1993 IRP, it is 40 MW more than AEPCO has committed to acquiring as of December 1993.

Companies' responsibilities to develop and implement their own Plans and desire to minimize inserting the Commission or other parties unduly into those responsibilities. The IRP process is intended to change the direction of Plans when those Plans do not fully take into account significant relevant factors such as future natural gas prices or the need for the Companies to actively participate in the development of cost-effective renewables. Because IRP is a dynamic activity, Staff has proposed that the set asides be "flexible" in order for the Companies and the Commission to be able to take into consideration changes in fuel costs, the costs of renewables, load forecasts, the need for additional capacity, and technology in future IRP proceedings.

Although we agree with the fundamental concept and recommendation that Staff has posited, we are concerned, however, that before we impose what will be in effect, mandatory long-term set asides (regardless of the "flexibility"), there needs to be additional notice and opportunity for the Companies and other interested parties to be able to respond to, and conduct additional study and planning for, such a requirement. We will, therefore, require that setting the appropriate long-term goals for the year 2009 become a topic of the working group (discussed hereinabove) and part of the discussion paper that will be submitted to the Commission.

Further, the LAW Fund has recommended that the Commission direct the Companies to develop comprehensive renewable resource plans as part of their next IRP filing that aim at capturing the full potential of renewable resources to serve electricity needs. Such comprehensive plan should address the following key elements:

- developing an information base on renewable resources on which Arizona utilities may rely;

- providing for a sustained, focused research, development, and demonstration effort aimed at preparing the way for the utilization of viable renewable resource technologies;
- assuring that IRPs developed by utilities in Arizona take advantage of renewables;
- proposals for fine-tuning the Commission's regulatory policies so that they encourage utility renewable resource initiatives that are consistent with the first three elements; and
- evidence that the Companies are tapping the increasing federal funding support for renewable resources.

We concur with the LAW Fund that the Companies should include the above elements in their next IRP filings. Further, notwithstanding the opposition expressed in this proceeding by the Companies regarding long-term set asides, if by the next IRP filing the respective Companies do not propose in their Plans reasonable alternatives to Staff's recommendations regarding the set asides, the Commission will reconsider adopting Staff's recommendations regarding mandatory, albeit flexible, set asides to be implemented by the year 2009.

Short-Term Set Asides

Until recently, renewable energy efforts by the Companies have been primarily either research and development efforts or small-scale early applications installed by innovative field engineers. Staff argued that it is time to accelerate these efforts for several reasons, including the following:

- there may be significant production economies-of-scale as renewables move into mass production, driving down the cost of renewable-generated electricity;
- economies-of-scale in production can be achieved through coordinated, joint purchases to establish viable markets for the new technologies; and
- renewable technologies are significantly different from conventional, fossil fuel technologies, requiring new technology learning curves that should be started

> immediately for renewables to be implemented within the planning horizon. In order for renewable energy to be effectively included in the generation mix in future years, utility personnel must start today to learn about the characteristics of renewables in utility systems. The best way for utilities to learn is to start, on a small scale, with the design, installation, and operation of renewable systems. Then, probably after the turn-of-the-century, the Companies will be prepared to install the multi-megawatt and hundreds of megawatt renewable plants that will be required.

The LAW Fund agreed with Staff that developing renewable resource programs to achieve short-term renewable resource acquisition goals will help ensure that the Companies make a significant contribution to the development of solar resource technologies without carrying a disproportionate share of the regional or nationwide financial burden. The LAW Fund noted that this commitment will serve several important purposes such as:

- a means to exert market pull to reduce the ultimate direct costs of renewable resource technologies;
- enabling the Companies to gain experience with these resources; and
- signaling the Companies' IRP commitment to develop these renewables as cost-effective electric system resources.

Staff has recommended that at a minimum, the Plans due to be filed by December 31, 1995 include the following mandatory short-term set asides for renewables to be implemented not later than December 31, 2000:

AEPCO	1,000 kw[25]
Citizens	1,000 kw
TEP	5,000 kw
APS	12,000 kw

Under Staff's proposal, the Companies should be allowed to credit renewable energy systems installed between January 1, 1993 to December

[25] In the case of AEPCO, projects undertaken by member cooperatives can be counted toward the goal.

31, 2000 toward their respective short-term set asides. The intent of the short-term set asides is to enhance learning about renewables to prepare for larger efforts that will probably be required after 2000.[26]

During the hearing, APS indicated that it is willing to strive toward a "goal" of 12 MW for renewables by 2000 and TEP indicated that it is willing to strive toward a goal of 5 MW for renewables by 2000. We regard these statements as serious commitments and will accept them as planning goals which are predicated upon articulated assumptions. However, if APS and TEP appear to fall significantly short of meeting these goals, we shall reconsider short-term set asides. If assumptions in setting these goals do not materialize, the goals may be revisited and modified in keeping with the facts known at such time. As for Citizens and AEPCO, we find that the short-term set asides of 1 MW each are reasonable and, to be consistent with our treatment of APS and TEP hereinabove, will treat these set asides as planning goals for the year 2000.

Finally, although we will not adopt the targets proposed by the LAW Fund, we encourage the Companies to consider Green Requests for Proposals (RFPs)[27] for renewables as a means of implementing the short-term goals and, in all likelihood, future long-term set asides.

<u>Other Issues Regarding Renewables</u>

Staff also made the following recommendations on renewable energy sources:

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[26] The short-term set asides can be counted toward the long-term set aside requirements that may be required in the future.

[27] Green Requests for Proposals (RFPs) is a competitive bid solicitation process used as a means for a utility to acquire renewable resources from third parties.

- each utility must develop a database of existing renewable energy resources within its system within six months from the effective date of this Decision. These inventories should be revised annually and submitted to the Commission Staff each year as part of the historical data filings required under the IRP rules;
- each utility should prepare a three year renewable resource action plan as part of its filing requirements for an action plan under the Commission's IRP rules, starting with the plans to be submitted by December 1995;[28]
- the Companies should include in their next Plans (to be filed by December 31, 1995) explicit discussions of their research and development plans and activities regarding renewables, including descriptions of projects undertaken and costs of those projects;
- the Commission should consider (in rate cases) allowing cost recovery for prudent investments in renewable generation demonstration projects (such as Solar Two) to better determine the costs and output potential of the technology;
- the Companies should recover prudent costs of set aside renewable resources (within limits on the cost per kw to be determined in future resource planning hearings or rate cases) after Commission consideration of utility cost estimates and proposals for cost recovery. The criteria for determining the limits on costs should include: estimates of costs from engineering studies or field experience; the costs of other (alternative) renewable technologies; the degree to which commercialization of the technology has progressed; and the likelihood that the proposed technology can be cost-effective in the future (if not currently cost-effective)[29]; and
- the Commission's policy stated in Decision No. 57589, concerning the provision of information on photovoltaics to potential line extension customers in remote areas, based on Staff guidelines, should be continued.

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[28] The LAW Fund recommends that the Commission order Arizona utilities to develop comprehensive renewable resource programs within one year from the effective date of this Decision. We find that Staff's proposal is similar and there is no need to adopt this proposal as well.

[29] If the costs turn out to be greater than the limits, the utility could request that the Commission raise the limit. If the utility contemplates such a proposal, it should have well-documented, logical support for the request indicating that new information alters the situation.

TEP supports Staff's recommendation that TEP be allowed to recover costs incurred for participation in such pre-approved renewable projects. The Company indicated further that it should be permitted to include in rate base and earn a return on investments in renewables as such pre-approved renewable resources become a part of the resource mix. TEP also noted that such renewable capacity should be treated in a way that does not affect the determination of the amount of Springerville Unit No. 2 to be included in rate base.

We find that each of the Staff recommendations generally supports our commitment to renewables as expressed hereinabove, and we shall adopt them herein as modified. We believe that renewables capacity may be put into rate base (in rate cases) and earn a return, and we shall consider such proposals in rate cases. We further take note of TEP's concern about potential conflicts between the amount of Springerville Unit No. 2 which is rate-based and our requirements on renewables. Since we have not ordered any mandatory renewable amounts, we do not find any conflicting policies.

The LAW Fund has also recommended that the Companies consider Green Pricing Programs, which offer consumers the opportunity to purchase greater amounts of renewable resource produced electricity than a utility or regulatory commission believes all utility customers should support. The Commission will not at this time require the implementation of Green Pricing Programs.

Other Supply Issues

We conclude that competitive bidding may be used to obtain utility resources, but also that such bidding processes must be founded on a thorough understanding of transaction costs so that contracts can be written which result in power and energy when needed at reasonable cost without unduly transferring risks to the utility or the ratepayer. Competitive bidding is useful but it is not a panacea. At the same time, we also recognize that through its consideration of transaction costs, a utility could use the bidding process to engage in self-dealing or other practices that are not least cost. Staff recommends that any Companies who wish to engage in supply or demand side bidding inform Staff of all requests for bids at least 45 days prior to issuing the request and submit to Staff a complete report on the bids, the utility's evaluation of the bids, and the utility's selection of the winner(s) no more than 30 days after selecting winning bids. We find Staff's recommendation regarding competitive bidding reasonable and shall adopt it herein[30].

With regard to state regulatory responsibilities and Regional Transmission Groups, we shall require Staff to continue to participate in Southwestern Regional Transmission Association ("SWRTA") meetings on a regular basis to keep informed of transmission planning issues.

Staff argued that at present, there are no useful analyses of savings in transmission and distribution costs resulting from DSM. Consequently, it is not possible to adequately quantify the benefits of avoiding or deferring transmission and distribution costs when we evaluate demand side management measures. Staff recommended that the Companies include in future Plans explicit analyses of the changes in their transmission and distribution plans and associated savings attributable to demand side management programs. We concur. Estimates of transmission and distribution savings should be determined from site-specific evaluations, considering deferrals of

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[30] This competitive bidding process does not apply to AEPCO's competitive proposal solicitation process that is currently underway.

transmission and distribution capacity resulting from planned DSM programs.

With regard to Exempt Wholesale Generators (EWGs), in Decision No. 58424 (October 14, 1993), we declined to adopt the Section 712 standards. We reaffirm our position in that discussion.

Under PURPA, utilities are obligated to purchase energy and power from qualifying cogenerators and small power producers at rates up to the utility's avoided costs. However, the Companies have not offered capacity payments for purchases of power from qualifying facilities. In our previous IRP Decision, the Commission ordered the Companies to file proposed capacity and energy rates for purchases from qualifying facilities ("QFs") in their 1992 resource planning filings. Only APS filed capacity rates.

Staff developed capacity payments for QFs offering power starting in 1994 based upon deferral of the next power plant planned by each utility, assuming contracts of various lengths and considering whether the QF wants payments to begin in 1994 (up-front payments) or is willing to wait for capacity payments until the year the utility would otherwise need to add capacity. Under Staff's proposal, the present value of capacity payments should equal the present value of the deferral of capacity costs. Staff recommended that the Companies submit values for capacity payments for Staff review and approval using the principles underlying the values in Staff Report Table 4, page E-52, within six months from the effective date of this Decision. The values in the Table (or Staff updates of these values) would be used if the utility does not submit the capacity values.[31]

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[31] AEPCO has taken exception to the use of the next avoided unit as the basis for calculating capacity payments. If the Utilities have a method of calculation for capacity payments that

We shall adopt Staff's recommendations regarding capacity payments for purchases from QFs over 100 kw. Additionally, we shall require that the Companies include in their filings maximum payments for energy from QFs over 100 kw reflecting avoided fuel and variable operating and maintenance costs, considering system conditions, and the characteristics of QF power. These maximum payments may be adjusted from time to time and may be reduced in the course of individual contract negotiations.

Intervenor Schmidt presented evidence regarding global warming. Mr. Schmidt recommended that the Commission order the Companies to provide a carbon dioxide mitigation scenario with their next IRP filings. We agree that global warming due to increasing levels of greenhouse gases and carbon dioxide is an important environmental and societal issue and encourage the Companies to consider the impact of such in their next IRP filings. Further, consideration of any such impact(s) should be consistent with the findings and guidelines developed by the Externalities Prioritization Working Group pursuant to Decision No. 57589 and any subsequent rules.

IV. Load Forecasting

The Staff Report found (and no party disputed) that load forecasting is a pivotal element of IRP. The load forecast drives the selection of supply and demand side resources over the planning horizon. However, any forecast, especially one that makes predictions twenty years into the future, may be in error. Hence, the Companies sometimes make a range of forecasts to develop a flexible set of plans to deal with uncertainty about the future.

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differs from the underlying principals presented by Staff, they may submit such method to Staff for approval.

Staff developed a set of load forecasts as an independent check on the Companies' forecasts. The purpose of the Staff forecasts is not to argue that one forecast is right and the other wrong, but to ascertain whether the base case forecasts of the Companies are reasonable given forecasts on population, employment, and other factors and given historical trends in factors affecting the demand for electricity. If the Staff forecasts are consistent with the Companies' forecasts, it can be inferred that there are no readily apparent factors that we expect would cause utility demand to greatly deviate from forecasted future demand. If the Staff forecasts are not consistent with the Companies' forecasts, it can be inferred that at least one set of forecasts has not properly considered available information or that the utility is facing a very uncertain future.

In this Docket, the Companies' long range forecasts of retail MW demand show that growth rates are expected to average between 2 and 3 percent per year between 1993 and 2002, except for Citizens, which expects an average annual growth rate of 3.9 percent. Staff concluded that APS', TEP's,[32] SRP's, AEPCO's and Citizens'[33] forecasts are consistent with Staff's forecasts through about 2002. No party disputed Staff's conclusions.

We find that Staff's load forecasts are consistent with the Companies' forecasts for the next ten years, given uncertainties about

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[32] TEP's forecast assumes that additional mining operations will add new loads between 1993 and 1997. Staff Forecast A for TEP includes additional mining loads and is comparable to TEP's forecast. However an alternative forecast should also be considered that reflects the uncertainty associated with the timing of mining additions. Staff Forecast B assumes that no significant mining additions occur during the forecast period.

[33] It appears that Citizens' growth is considerably higher than the other utilities due to continued high customer growth in the Mohave area.

electricity demand in the mining sector. In particular, there is some uncertainty about demand in TEP's service area due to uncertainty about the dates when additional mining loads may come into existence. Because TEP is not planning to add any supply side resources until 2002, there is no immediate practical effect of possible errors in demand forecasts that cannot be rectified in future load forecasts and resource plans as more information becomes available. Additionally, there is considerable uncertainty regarding AEPCO's future load because of uncertainty about mining loads. To a large extent, AEPCO's member cooperatives must manage that uncertainty as they negotiate special contracts with mining customers.

We also agree with Staff with respect to the difficulties of implementing forecasting models that rely upon end use data. Such models can provide additional insight into load growth. For such a model to be most useful, however, detailed data is required. We will, therefore, require the Companies to increase their collection of end use load data, to obtain commercial and industrial energy sales data by Standard Industrial Classification ("SIC") category, and to collate that information with data on commercial and industrial customers such as number of employees in each SIC category. The ability to forecast demand for commercial and industrial customers depends on having such disaggregated data. We will also require that the Companies coordinate with Staff their efforts to collect the data described above and that the Companies include this data in their annual IRP data filings, beginning with their next filing.

V. Administrative Matters

After reviewing the Plans for both 1989 and 1992, Staff believes several generic improvements can be made. In particular, Staff proposed the following features for future Plans filed with the Commission:

- the Plan should have a comprehensive, self-explanatory load and resources table summarizing the utility's Plan;
- the Plan should have an easy-to-read, brief executive summary that will inform the public about the utility's Plan and the load and resources table should be included in the executive summary. The executive summary can be provided to people requesting copies of the Plan instead of copying voluminous technical information that is of little value to individuals interested in a non-technical report;
- voluminous computer output is discouraged; it is usually incomprehensible, it needs interpretation, and it wastes paper;
- the Plan should be in the form of a narrative leading the reader to logical conclusions and supported by tables, graphs, charts, etc;
- the Plan should be indexed to indicate where the filing requirements can be found (see APS' Plan for an example);
- terms should be defined as they are used by the utility; for example, utilities use the term "forced outage rate" differently and it is not always clear whether demand includes or excludes sales for resale; and
- the Companies should strive for consistency in data and assumptions throughout their Plans.

As there was no opposition to these recommendations and because these recommendations will improve the readability and usefulness of the Plans, we will adopt them herein.

VI. Summary

Based upon the record in this proceeding and the foregoing analysis, we find that Plans submitted are generally consistent with the IRP requirements set forth in A.A.C. R14-2-701 et seq. Further, the record establishes that additional requirements should be imposed on the respective parties in the manner set forth hereinbelow.

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. APS, TEP, AEPCO, and Citizens (collectively "Companies") are certificated to provide electric utility service to the public in portions of Arizona pursuant to authority granted by the Commission.

2. SRP is an agricultural improvement district duly organized and existing under Title 48, Chapter 17 of the laws of the State of Arizona, and is a political subdivision of the State of Arizona pursuant to Article 13, section 7 of the Arizona Constitution. SRP is principally engaged in the generation of electricity in the States of Arizona, New Mexico, Nevada and Colorado, and the purchase and sale of electricity to customers in Maricopa, Pinal, and Gila Counties in the State of Arizona.

3. Southwest Gas is a California corporation engaged in the business of providing natural gas utility service to the public in portions of Arizona pursuant to the authority granted by the Commission.

4. ACAA is an Arizona non-profit organization that helps low-income people become self sufficient.

5. The LAW Fund is a western regional environmental organization committed to reducing the environmental impacts associated with meeting the need for utility energy services.

6. Pursuant to A.A.C. R14-2-703, the Companies filed their respective 1992 Plans.

7. Pursuant to A.A.C. R14-2-704.A, the Commission must schedule a hearing to review the Companies' Plans and to evaluate those Plans

in light of analyses by Staff and others within 120 days of the filing dates.

8. SRP agreed to participate in the IRP process on a voluntary basis and filed its Plan.

9. Pursuant to the September 9, 1993 Procedural Order, this matter was set for hearing commencing on December 7, 1993.

10. Intervention in this matter was granted to RUCO, SRP, Southwest Gas, ACAA, the LAW Fund, Phelps Dodge Corporation, Don't Waste Arizona, Inc., Cyprus Mineral Company, and Mr. Lothar M. Schmidt.

11. Workshops were held on October 8, 18, 19 and 20, 1993 at the Commission's offices.

12. The hearing commenced on December 7, 1993.

13. The purpose of IRP is to minimize the total societal cost of meeting the demand for electric energy services giving due consideration to ratepayer impacts, utility financial health and economic growth within a utility's service area.

14. The goal of resource planning can be achieved by finding the mix of supply and demand side resources that minimize society's costs.

15. Electric utilities are coming under increasing competitive pressure to keep prices to their customers low. Impacts on the competitive position of Arizona's utilities warrant specific consideration in the development and implementation of IRPs.

16. DSM is the systematic effort to improve the efficiency of using electric energy and power.

17. DSM is cost-effective if reductions in power usage at peak production times for the utility and reductions in energy usage at any time are less costly to society than generating, transmitting, and

distributing electricity, including building of any new generation, transmission, or distribution capacity.

18. The Commission has established a cost recovery mechanism for DSM programs for APS, TEP, Citizens, AEPCO, and several distribution cooperatives.

19. To be eligible for the cost recovery mechanism, a DSM program must be pre-approved by the Commission Staff.

20. The Companies' projections indicate that sales will be reduced by about 1160 MW by the year 2010 as a result of DSM undertaken between 1993 and 2010.

21. Cost-effective residential retrofit programs aimed at low-income customers would be consistent with the basic purpose of IRP which is to meet the demand for electric energy services at minimum cost.

22. Monitoring of DSM programs serve several purposes: to determine participation rates and kw and kwh savings; to provide a foundation for recovery of lost net revenues and incentives to the utility based on kw or kwh savings (if authorized by the Commission); to evaluate the process by which the utility implements its DSM programs; and to provide information on whether to continue, modify, or terminate a program.

23. As a potential addition to the menu of DSM programs offered by the Companies, the Companies should consider a design team approach to new commercial buildings to encourage the construction of energy efficient new buildings.

24. The Companies must first offer and promote cost effective energy efficiency measures when negotiating special contracts that offer discounted rates to attract or retain a business.

25. A Staff directed DSM workshop on the topic of repayment of incentives out of savings is necessary and such a workshop should include consideration of the bonus payment proposal by the LAW Fund.

26. The Companies, especially TEP and APS, should increase their respective DSM activities and accelerate DSM targets in the next IRP filing.

27. If the Companies do not accelerate their DSM activities, specific targets should be considered in future IRP hearings.

28. There should be no specific targets for low-income programs, but APS should begin a low-income pilot program with potentially cost effective DSM measures and then, after one year, modify the program as appropriate.

29. TEP should use the results of its current low-income program to develop a larger, cost-effective low-income DSM program.

30. The Companies should consider in their next IRP filing whether fuel switching as a DSM resource potential is an option.

31. Within twelve months from the effective date of this Decision, each of the Companies must solicit from parties to this Docket (and other interested parties who make themselves known to the utility) specific proposals for DSM measures, programs, and screening prior to preparing its Plan for the next required IRP filing and conduct a workshop (or workshops if more than one workshop is needed) on its DSM proposals. Staff should coordinate and establish a schedule for such workshops. The schedule for the workshops should allow sufficient time for the parties to ask the Companies for information relevant to the DSM programs.

32. The proposed workshop for each utility described in the above finding will promote greater public participation in the DSM

planning process without removing from the Companies their responsibilities to develop and implement DSM programs and without removing from Staff its responsibilities to review those programs. The parties to the workshops should discuss the relative merits of expensing versus capitalizing DSM program costs and net lost revenues.

33. Although the Companies prepare regular reports to Staff on progress with their DSM programs, some parties have not found these reports easy to obtain.

34. Each utility should file one copy of its DSM reports with the Commission's Docket Control for better public access.

35. In order for interested parties to have more direct input into the DSM recovery process, Companies that file for pre-approval of DSM programs for which recovery is sought should file a notice of such filing and a copy of such plan with the Commission's Docket Control and notify all interested parties of the filing. Interested parties shall then have 20 days to file any written comments with Staff.

36. Upon Staff's pre-approval, Staff shall submit the projects to the Commission for its consideration and preliminary adoption and if the Commission adopts the pre-approval, the projects shall be considered approved for cost-recovery in future rate proceedings. The Commission, however, reserves the right to review the projects in future rate proceedings, if necessary, to make a final determination with respect to the appropriateness of the cost-recovery.

37. Utility progress on M&E evaluation is hard to judge since monitoring efforts are still underway.

38. Evaluation of kw and kwh savings should be conducted using state-of-the-art methods in a competent, scientific manner; data and

results should provide a comprehensive, internally consistent account of the savings from DSM.

39. Advertising appears to be growing in importance as a cost element of DSM programs. The Companies should include in pre-approval filings a monitoring plan for advertising for each DSM program whose advertising costs are budgeted to exceed $100,000 per year for AEPCO and Citizens and $300,000 for TEP and APS.

40. The Companies should measure the impact of free ridership and free drivers on the level of savings associated with their DSM programs in cases where such effects are likely to be important and significantly influence the cost-effectiveness of a DSM program.

41. The review of M&E of DSM should be a public process and APS, TEP, AEPCO, and Citizens should each make an annual presentation at workshops covering the following topics:

- study designs for DSM programs for which monitoring is required (as indicated in Staff's pre-approval letter) and for which monitoring has not yet begun or is about to begin (including process evaluations);
- progress reports on M&E projects underway (including process evaluations); and
- results from M&E projects that have been completed during the previous year or are near completion (including process evaluations).

42. Financial barriers to DSM have led the Commission to develop mechanisms for program cost recovery, recovery of lost net revenues, and recovery of a profit or reward to make the utility indifferent between traditional supply side resources and DSM.

43. Currently, APS has a $4 million cap in place on recovery of DSM costs.

44. In TEP's recent rate case, cost recovery is limited in magnitude by TEP's plans as of the time of the rate case hearing.

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45. A deferred accounting approach should be adopted in which APS and TEP (and any other utility desiring a deferred accounting) should file an application for Commission approval which contains: a DSM savings target; a specific DSM program consisting of cost-effective DSM measures; an effective M&E plan; and a program designed to manage revenue impacts to the utility and ratepayers.

46. It would be useful for parties to this Docket to meet publicly with APS and TEP in workshops (prior to the Companies' filing for Commission approval of specific accounting authority) to discuss how the deferred accounting would work and to consider the rate impacts of the proposed level of deferrals.

47. For costs in excess of those included in base rates or existing capped surcharges, deferred accounting is appropriate if ratepayers have a reasonable probability of getting the savings DSM programs can provide.

48. Costs to be included in the deferral account are program costs (e.g., administrative costs, rebates, M&E costs, etc.) and lost net revenues, (if already authorized) and, if already authorized, a reward for deferring the return on capacity additions deferred by DSM.

49. Costs may only be entered into the deferral account if they are associated with programs pre-approved by Staff and when kw and kwh savings are reasonably probable and can be analyzed and measured using monitored data (following a public review of the analysis in the annual workshops on M&E).

50. Program costs may be entered in the deferral account if they are associated with monitored pre-approved educational or research programs from which no kwh or kw savings can be practically derived.

51. Costs included in the deferral account may be recovered at

the next rate case, possibly amortized over several years because of their potentially large magnitude.

52. Consistent with Decision No. 57589, deferred amounts may accrue interest at the approved cost of capital of the utility.

53. The Commission encourages the parties to bring forth innovative ideas on how to unlink revenues and sales in future IRP proceedings.

54. The Commission will consider incentives for DSM that focus on recovery of program costs, recovery of lost net revenues, and, if appropriate, recovery of a reward for deferring returns on future capacity.

55. The Commission has considered the new PURPA standards regarding IRP in the Energy Policy Act of 1992 through its IRP rules (A.A.C. R14-701 et seq.) which have been in effect since 1989, and through rate case decisions.

56. Arizona's IRP process meets the requirements of 40 CFR 73.82 (a)(4) and (a)(6) regarding allowances from the Conservation and Renewable Energy Reserve.

57. The benefits to the Companies with regard to gaining additional sulfur dioxide allowances should be considered in rate cases when determining whether to allow the utility to recover lost net revenues or rewards for DSM savings.

58. There is nothing that precludes a utility from filing for approval for recovery of high efficiency HVAC programs.

59. Between 1993 and 2010, the Companies plan to add approximately 2285 MW of new generating capacity at a cost (present value) of $812 million.

60. Most of the planned capacity to be added between 1993 and 2010 is gas-fired.

61. Combined cycle units comprise nearly half of the planned additions, combustion turbines account for about 25 percent of the new capacity, baseload units comprise 15 percent of the new capacity and the remainder consists of increasing the capacity of existing plants (uprating) and the use of other technologies, including 10 MW of photovoltaics and 2 MW of fuel cell production.

62. Common forms of renewable energy resources include: photovoltaics; solar thermal resources such as parabolic troughs, parabolic dishes, and central receivers; windpower; biomass consisting of wood, wood waste, agricultural waste, municipal solid waste, and landfill and digester gas; geothermal resources, including hydrothermal resources and hot dry rock; and hydropower.

63. A working group consisting of Staff and utility planners (as well as any other parties to this Docket who wish to participate) should be created to develop a framework (or frameworks) to thoughtfully handle uncertainty in supply side IRP decisions, and to complete a discussion paper within one year that collaboratively develops:

- a better understanding of how to evaluate the risks and benefits of gas-fired plants and renewable resources (with emphasis on solar thermal plants and possibly windpower), by inviting experts on decision analysis, solar and wind technology, and conventional technology to make presentations;
- A decision analysis of a generic combined cycle unit, a generic solar plant, and possibly a generic wind plant for the purpose of improving the parties' understanding of how to do such an analysis; and
- Suggestions on how the Companies should analyze the risks and benefits of renewables and conventional technology in their next Plans.

64. Staff should coordinate the working group's activities; details of the procedures used by the working group should be determined by the participants at the beginning of the process.

65. Staff recommended flexible, long-term, set asides for renewable resources of 40 MW each for AEPCO and Citizens, and set asides of 160 MW for APS and TEP to be added by 2009.

66. The Companies believe that Staff's proposal for set asides is premature and that additional study is needed before committing to renewables.

67. The time is ripe for serious consideration of renewables over the long run, well beyond the efforts described in the Companies' Plans.

68. Before the Commission imposes long-term set asides, there needs to be additional notice and opportunity for the Companies and other interested parties to be able to respond to, and conduct additionally study and planning for, such a requirement.

69. We will require that establishing the appropriate long-term goals for the year 2009 become a topic of the working group (discussed hereinabove) and part of the discussion paper that will be submitted to the Commission. Both MW and MWH goals should be a topic of discussion at the workshop and in the discussion paper.

70. The LAW Fund has recommended that the Commission direct the Companies to develop comprehensive renewable resource plans as part of their next IRP filing that aim at capturing the full potential of renewable resources to serve electricity needs. Such comprehensive plan should contain the following key elements:

- developing an information base on renewable resources on which Arizona utilities may rely;

- providing for a sustained, focused research, development, and demonstration effort aimed at preparing the way for the utilization of viable renewable resource technologies;
- assuring that IRPs developed by utilities in Arizona take advantage of renewables;
- proposals for fine tuning the Commission's regulatory policies so that they encourage utility renewable resource initiatives that are consistent with the first three elements; and
- evidence that the Companies are tapping the increasing federal funding support for renewable resources.

71. We concur with the LAW Fund that the Companies should include the above elements in their next IRP filings.

72. If by the next IRP filing, the respective Companies do not propose in their Plans reasonable alternatives to Staff's recommendations regarding the set asides, the Commission will reconsider Staff's recommendations regarding long-term set asides to be implemented by the year 2009.

73. Staff has recommended that, at a minimum, the Plans due to be filed by December 31, 1995 include the following mandatory targets for renewables to be implemented not later than December 31, 2000:

AEPCO	1,000 kw[34]
Citizens	1,000 kw
TEP	5,000 kw
APS	12,000 kw

74. Under Staff's proposal, the Companies should be allowed to credit renewable energy systems installed between January 1, 1993 to December 31, 2000 toward the short-term goal.

75. The intent of the short-term set asides is to enhance learning about renewables to prepare for larger efforts after 2000.

[34] In the case of AEPCO, projects undertaken by member cooperatives can be counted toward the goal.

76. The short-term set asides may be counted toward any long-term set aside goals that may be ordered in the future.

77. APS indicated that it is willing to strive toward a goal of 12 MW for renewables by 2000 and TEP indicated that it is willing to strive toward a goal of 5 MW for renewables by 2000.

78. These are serious commitments and should be considered planning goals which are predicated upon articulated assumptions. If, however, APS and TEP appear to fall significantly short of meeting these goals, short-term set asides should be reconsidered. If assumptions in setting these goals do not materialize, the goals may be revisited and modified in keeping with the facts known at such time.

79. As for Citizens and AEPCO, the short-term set asides of 1 MW each are reasonable and these set asides should also be considered planning goals for the year 2000.

80. The Companies should use the nameplate rating of a renewable generating resource when crediting a resource toward the set aside; this procedure is administratively easier than trying to devise methods to make renewable capacity equivalent to combined cycle or combustion turbine capacity and it reflects the fact that renewables may be produced in ways not directly comparable to conventional central station generators.

81. The Companies are encouraged to consider RFPs for renewables as a means of implementing the short-term goals and possible long-term set asides that may be required in the future.

82. Each of the Companies should develop a data base of existing renewable energy resources within its system within six months from the effective date of this Decision; these inventories should be

revised annually and submitted to Staff each year as part of the historical data filings required under the IRP rules.

83. Each of the Companies should prepare a three year renewable resource action plan as part of its filing requirements for an action plan under the Commission's IRP rules, starting with the Plans to be submitted by December 31, 1995.

84. The Companies should include in their IRP Plans (to be filed by December 31, 1995) explicit discussions of their research and development plans and activities regarding renewables, including descriptions of projects undertaken and costs of those projects.

85. Consideration should be given in rate cases of allowing cost recovery for prudent investments in renewable generation demonstration projects (such as Solar Two), whose purpose is to better determine the costs and output potential of the technology.

86. The Companies should recover prudent costs of set aside renewable resources (within limits on the cost per kw to be determined in future rate cases) after Commission consideration of utility cost estimates and proposals for cost recovery; the criteria for determining the limits on costs should include: estimates of costs from engineering studies or field experience; the costs of other (alternative) renewable technologies; the degree to which commercialization of the technology has progressed; and the likelihood that the proposed technology can be cost effective in the future (if not currently cost effective)[35].

87. The Commission's policy stated in Decision No. 57589 concerning the provision of information on photovoltaics to potential

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[35] The proposed technology must reasonably be expected to show cost effectiveness as soon as practical, but in no event longer than 10 years from the date the utility requests recovery.

line extension customers in remote areas, based on Staff guidelines, should be continued.

88. Proposals that renewable capacity may be put into rate base and earn a return shall be considered in rate cases.

89. The Companies may consider Green Pricing Programs and the Companies may discuss this in their next IRP filing.

90. Competitive bidding may be used to obtain utility resources, but such bidding processes should be founded on a thorough understanding of transaction costs so that contracts can be written which result in power and energy when needed at reasonable cost without unduly transferring risks to the utility or the ratepayer.

91. The Companies who wish to engage in supply or demand side competitive bidding should inform Staff of all requests for bids at least 45 days prior to issuing the request and submit to Staff a complete report on the bids, the utility's evaluation of the bids, and the utility's selection of the winner(s) no more than 30 days after selecting winning bids.

92. Staff should continue to participate in SWRTA meetings on a regular basis to keep informed of transmission planning issues.

93. The Companies should include in future Plans explicit analyses of the changes in their transmission and distribution plans and associated savings attributable to DSM programs.

94. With regard to EWGs in Decision No. 58424 (October 14, 1993), we declined to adopt the Section 712 standards and we reaffirm our position.

95. Under PURPA, utilities are obligated to purchase energy and power from qualifying cogenerators and small power producers at rates up to the utility's avoided costs.

96. Staff developed capacity payments for Qfs offering power starting in 1994 based upon deferral of the next power plant planned by each utility, assuming contracts of various lengths and considering whether the QF wants payments to begin in 1994 (up-front payments) or is willing to wait for capacity payments until the year the utility would otherwise need to add capacity.

97. The present value of capacity payments should equal the present value of the deferral of capacity costs.

98. The Companies should submit values for capacity payments to QFs over 100 kw for Staff review and approval using the principles underlying the values in Staff Report Table 4, page E-52, within six months from the effective date of this Decision; the values in the Table (or Staff updates of these values) would be used if the utility does not submit the required capacity values.

99. The Companies should include in their filings maximum payments for energy from QFs over 100 kw reflecting avoided fuel and variable operating and maintenance costs, considering system conditions, and the characteristics of QF power. These maximum payments may be adjusted from time to time and may be reduced in the course of individual contract negotiations.

100. Because AEPCO's member cooperatives make arrangements with QFs, we will also require that, after Staff has determined that AEPCO's buyback rates for QFs over 100 kw are in compliance (or that the Staff values should be used), AEPCO should file jointly with each of its Arizona member cooperatives appropriate buyback rates that will be paid by the member cooperatives to QFs over 100 kw.

101. Because deferred capacity costs and avoided energy costs will vary over time, the Companies should revise their buyback rates accordingly.

102. The possibility of global climate change due to increasing levels of greenhouse gases is an important environmental and societal issue. Thus, the Companies are encouraged to consider the impact of this issue in their next IRP filings. Consideration of any such impact(s) should be consistent with the findings and guidelines developed by the Externalities Prioritization Working group pursuant to Decision No. 57589 and any subsequent rules.

103. The Companies' long range forecasts of retail MW demand show that growth rates are expected to average between 2 and 3 percent per year between 1993 and 2002, except for Citizens, which expects an average annual growth rate of 3.9 percent.

104. Staff's load forecasts are consistent with the Companies' forecasts for the next ten years, given uncertainties about electricity demand in the mining sector.

105. Models which use end use data can provide additional insight into load growth; however, for such models to be most useful, detailed data is required.

106. The Companies should increase their collection of end use load data, obtain commercial and industrial energy sales data by Standard Industrial Classification (SIC) category, and collate that information with data on commercial and industrial customers such as number of employees in each SIC category.

107. The Companies should coordinate with Staff their efforts to collect the data described above and must include the data described above in their next annual IRP data filings.

108. To improve Plans we shall require the following features in all future IRP filings:

- each Plan should have a comprehensive, self-explanatory load and resources table summarizing the utility's Plan;
- each Plan should have an easy-to-read, brief executive summary that will inform the public about the utility's plan; the load and resources table should be included in the executive summary;
- voluminous computer output is discouraged; it is usually incomprehensible, it needs interpretation, and it wastes paper;
- the Plan should be in the form of a narrative leading the reader to logical conclusions and supported by tables, graphs, charts, etc.;
- each Plan should be indexed to indicate where the filing requirements can be found (see APS' plans for an example);
- terms should be defined as they are used by the utility; and
- the Companies should strive for consistency in data and assumptions throughout their Plans.

CONCLUSIONS OF LAW

1. APS, TEP, AEPCO and Citizens are Arizona public service corporations within the meaning of Article XV of the Arizona Constitution.

2. The Commission has jurisdiction over APS, TEP, AEPCO, Citizens, and Southwest Gas and over the subject matter of the Plans.

3. A.A.C. R14-2-703.F requires each electric utility under the Commission's jurisdiction which operates or owns generating facilities to file with the Commission a Plan every three years.

4. A.A.C. 14-2-704.A requires the Commission to schedule a hearing to review the Plans and to determine the degree of consistency between these Plans and the analyses conducted by Staff and other parties within 120 days of the submission of the Plans.

5. The Plans submitted by APS, TEP, AEPCO and Citizens are consistent within the meaning of A.A.C. R14-2-704.

6. The parties to this proceeding should comply with the requirements set forth hereinbelow.

ORDER

IT IS THEREFORE ORDERED that the 1992 Integrated Resource Plans submitted by Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company are hereby consistent in accordance with A.A.C. R14-2-704.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall either develop a design team approach to new commercial buildings to encourage the construction of energy efficient new buildings, or indicate in their regular reports on DSM programs, within one year from the effective date of this Decision, why design teams are not appropriate.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall first offer and promote cost effective energy efficiency measures when negotiating special contracts that offer discounted rates to attract or retain a business.

IT IS FURTHER ORDERED that Staff shall undertake a workshop on repayment programs, including the Land and Water Fund of the Rockies' bonus program.

IT IS FURTHER ORDERED that Arizona Public Service Company shall begin a low-income pilot program with potentially cost-effective DSM measures and then, after one year, modify the program as appropriate.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall use the results of its current low-income program to develop a larger, cost-effective low-income DSM program.

IT IS FURTHER ORDERED that within twelve months of the Commission's decision in each IRP review, each utility shall solicit from parties to this Docket (and other interested parties who make themselves known to the utility) specific proposals for DSM measures, programs, and screening prior to preparing its Plan for the next required filing and conduct a workshop, as coordinated by Staff, on DSM proposals.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall consider in their next IRP filing whether fuel switching as a DSM resource potential is an option.

IT IS FURTHER ORDERED that each utility shall file one copy of its DSM reports with the Commission's Docket Control.

IT IS FURTHER ORDERED that each utility that files for pre-approval of a DSM program shall file a notice of such filing and a copy of such plan with the Commission's Docket Control and shall notify all interested parties (as defined in the Discussion hereinabove) of the filing; such interested parties shall then have 20 days to file any written comments with Staff to be taken into consideration.

IT IS FURTHER ORDERED that upon Staff's pre-approval, Staff shall submit the projects to the Commission for its consideration and preliminary adoption and if the Commission adopts the pre-approval, the projects shall be considered for cost-recovery in future rate proceedings.

IT IS FURTHER ORDERED that the Commission reserves the right to review pre-approved projects in future rate proceedings, if necessary, to make a final determination with respect to the appropriateness of the cost-recovery.

IT IS FURTHER ORDERED that evaluation of kw and kwh savings shall be conducted using state-of-the-art methods in a competent, scientific manner; data and results should provide a comprehensive, internally consistent account of the savings from DSM.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall include in pre-approval filings a monitoring plan for advertising for each DSM program whose advertising costs are budgeted to exceed $100,000 for AEPCO and Citizens and $300,000 for APS and TEP, and for advertising costs less than that amount, such expenditures should be supported by explaining the objective, intended target audience, estimated costs and intended media.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall measure the impact of free ridership and free drivers on the level of savings associated with their DSM programs in cases where such effects are likely to be important and significantly influence the cost-effectiveness of a DSM program.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall each make an annual presentation at workshops covering the following topics:

. . .

- study designs for DSM programs for which monitoring is required (as indicated in Staff's pre-approval letter) and for which monitoring has not yet begun or is about to begin (including process evaluations);

- progress reports on M&E projects underway (including process evaluations); and

- results from M&E projects that have been completed during the previous year or are near completion (including process evaluations).

IT IS FURTHER ORDERED that Arizona Public Service Company and Tucson Electric Power Company shall file for approval of an accounting order to defer DSM costs in excess of those included in base rates or existing capped surcharges.

IT IS FURTHER ORDERED that the applications for deferred accounting shall include DSM savings targets, monitoring plans, cost-effective DSM measures, and program designs to manage the costs of DSM.

IT IS FURTHER ORDERED that program costs, lost net revenues (if authorized), and a reward (if already authorized), shall be entered into the deferral account if they are associated with programs pre-approved by Staff and when kw and kwh savings have been demonstrated using monitored data (following a public review of the analysis in the annual workshops on M&E); additionally, program costs may be entered in the deferral account if they are associated with monitored pre-approved educational or research programs from which no kw or kwh savings can be practically derived.

IT IS FURTHER ORDERED that workshops on proposed deferred accounting shall be held prior to a utility filing for deferred accounting related to its DSM programs.

IT IS FURTHER ORDERED that the Commission has hereby considered the new PURPA standards through its IRP rules (A.A.C. R14-701 et seq.) which have been in effect since 1989 and through rate case decisions.

IT IS FURTHER ORDERED that the IRP process hereby meets the criteria for obtaining Conservation and Renewable Energy Reserve allowances.

IT IS FURTHER ORDERED that the benefits to Arizona utilities with regard to gaining additional sulfur dioxide allowances shall be considered in rate cases when determining whether to allow the utility to recover lost net revenues or rewards for DSM savings.

IT IS FURTHER ORDERED that nothing herein shall be considered to preclude a utility from filing for approval for recovery of high efficiency HVAC programs.

IT IS FURTHER ORDERED that a working group consisting of Staff and utility planners (as well as any other parties to this Docket who wish to participate) shall be created to develop a framework (or frameworks) to thoughtfully handle uncertainty in supply side IRP decisions (including setting the appropriate level of long-term goals), to complete a discussion paper within one year, and to collaboratively develop:

- a better understanding of how to evaluate the risks and benefits of gas-fired plants and renewable resources (with emphasis on solar thermal plants and possibly windpower), by inviting experts on decision analysis, solar and wind technology, and conventional technology to make presentations;
- a decision analysis of a generic combined cycle unit, a generic solar plant, and possibly a generic wind plant for the purpose of improving the parties' understanding of how to do such an analysis; and
- suggestions on how the Companies should analyze the risks and benefits of renewables and conventional technology in their next Plans.

IT IS FURTHER ORDERED that the appropriate long-term goals for the year 2009 become a topic of the working group and part of the discussion paper that will be submitted to the Commission.

IT IS FURTHER ORDERED that in the absence of viable alternatives, Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company, shall incorporate into their future Plans (and undertake commensurate research, development, commercialization, and implementation activities) appropriate levels of renewables.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company, shall develop comprehensive renewable resource plans as part of their next IRP filing that aim at capturing the potential of renewable resources to serve electricity needs that include the following:

- developing an information base on renewable resources on which Arizona utilities may rely;
- providing for a sustained, focused research, development, and demonstration effort aimed at preparing the way for the utilization of viable renewable resource technologies;
- assuring that IRPs developed by utilities in Arizona take advantage of renewables;
- proposals for fine tuning the Commission's regulatory policies so that they encourage utility renewable resource initiatives that are consistent with the first three elements; and
- evidence that the Companies are tapping the increasing federal funding support for renewable resources.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall strive for installing and operating the following amounts of renewable capacity not later than December 31, 2000:

Arizona Electric Power Cooperative	1,000 kw[36]
Citizens Utilities Company	1,000 kw
Tucson Electric Power Company	5,000 kw
Arizona Public Service Company	12,000 kw

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall be permitted to credit renewable energy systems installed between January 1, 1993 to December 31, 2000 toward the goal for the year 2000.

IT IS FURTHER ORDERED that renewables installed and operated by the year 2000 shall be counted toward any renewable capacity values established in future IRP proceedings.

IT IS FURTHER ORDERED that if any utility appears to fall significantly short of meeting the year 2000 renewables goals, the Commission may reconsider short-term set asides.

IT IS FURTHER ORDERED that if assumptions in setting these goals do not materialize, the goals may be revisited and modified in keeping with the facts known at such time.

IT IS FURTHER ORDERED that if by the next IRP filing, the respective Companies do not propose in their Plans reasonable alternatives to Staff's recommendations regarding the set asides, the Commission shall reconsider Staff's recommendations regarding long-term set asides to be implemented by the year 2009.

IT IS FURTHER ORDERED that each utility shall develop a database of existing renewable energy resources within its service area within six months from the effective date of this Decision; these inventories

[36] In the case of AEPCO, projects undertaken by member cooperatives can be counted toward the goal.

shall be revised annually and submitted to Staff each year as part of the historical data filings required under the IRP rules.

IT IS FURTHER ORDERED that each utility shall prepare a three year renewable resource action plan as part of its filing requirements for an action plan under the Commission's IRP rules, starting with the plans to be submitted by December 31, 1995.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall include in their next IRPs (to be filed by December 31, 1995) explicit discussions of their research and development plans and activities regarding renewables, including descriptions of projects undertaken and costs of those projects.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company are hereby authorized to recover the prudent costs of renewable resources within limits on the cost per kw to be determined in future rate cases after Commission consideration of utility cost estimates and proposals for cost recovery; the criteria for determining the limits on costs shall include: estimates of costs from engineering studies or field experience; the costs of other (alternative) renewable technologies; the degree to which commercialization of the technology has progressed; and the likelihood that the proposed technology can be cost effective in the future (if not currently cost effective)[37].

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[37] The proposed technology must reasonable be expected to become cost effective as soon a practical, but in no event longer than 15 years from the date the utility requests recovery.

IT IS FURTHER ORDERED that the Commission's policy stated in Decision No. 57589 concerning the provision of information on photovoltaics to potential line extension customers in remote areas, based on Staff guidelines, is hereby continued.

IT IS FURTHER ORDERED that proposals that renewable capacity may be put into rate base and earn a return shall be considered in rate cases.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company, may consider Green Pricing Programs and may discuss Green Pricing Programs in their next IRP filings.

IT IS FURTHER ORDERED that any utility that wishes to engage in supply or demand side bidding shall inform Staff of all requests for bids at least 45 days prior to issuing the request and submit to Staff a complete report on the bids, the utility's evaluation of the bids, and the utility's selection of the winner(s) no more than 30 days after selecting winning bids.

IT IS FURTHER ORDERED that Staff shall continue to participate in Southwest Regional Transmission Association meetings on a regular basis to keep informed of transmission planning issues.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall include in Plans or DSM reports explicit analyses of the changes in their transmission and distribution plans and associated savings attributable to DSM programs if they wish to take credit for such transmission and distribution savings.

IT IS FURTHER ORDERED that our decision to decline to adopt standards regarding Exempt Wholesale Generators, in Decision No. 58424 (October 14, 1993), is hereby reaffirmed.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall submit values for capacity payments to qualifying facilities over 100 kw for Staff review and approval using the principles underlying the values in Staff Report Table 4, page E-52, or such other principles as Staff the Companies may agree to, within six months from the effective date of this Decision.

IT IS FURTHER ORDERED that the values in the Staff Table (or Staff updates of these values) for capacity payments for purchases from qualifying facilities over 100 kw shall be used if the utility does not comply with the above paragraph.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall include in their filings maximum payments for energy from QFs over 100 kw reflecting avoided fuel and variable operating and maintenance costs, considering system conditions, and the characteristics of QF power. These maximum payments may be adjusted from time to time and may be reduced in the course of individual contract negotiations.

IT IS FURTHER ORDERED that after Staff has determined that Arizona Electric Power Cooperative's buyback rates for QFs over 100 kw are in compliance (or that the Staff values should be used), Arizona Electric Power Cooperative shall file jointly with each of its Arizona member cooperatives appropriate buyback rates that will be paid by the member cooperatives to QFs over 100 kw.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall revise their buyback rates regularly.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall increase their collection of end use load data, obtain commercial and industrial energy sales data by Standard Industrial Classification (SIC) category, collate that information with data on commercial and industrial customers such as number of employees in each SIC category, furnish Staff with a copy of the data to enable Staff to conduct independent analyses, and that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall include the data described above in their annual IRP data filings.

IT IS FURTHER ORDERED that future IRP Plans shall include the following:

- the Plan shall have a comprehensive, self-explanatory load and resources table summarizing the utility's Plan;
- the Plan shall have an easy-to-read, brief executive summary that will inform the public about the utility's Plan and the load and resources table should be included in the executive summary. The executive summary can be provided to people requesting copies of the Plan instead of copying voluminous technical information that is of little value to individuals interested in a non-technical report;
- voluminous computer output is discouraged; it is usually incomprehensible, it needs interpretation, and it wastes paper;
- the Plan shall be in the form of a narrative leading the reader to logical conclusions and supported by tables, graphs, charts, etc;
- the Plan shall be indexed to indicate where the filing requirements can be found (see APS' Plan for an example);

. . .

- terms shall be defined as they are used by the utility; for example, different utilities use the term "forced outage rate" differently and it is not always clear whether demand includes or excludes sales for resale; and

- the Companies shall strive for consistency in data and assumptions throughout their Plans.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN   COMMISSIONER   Dale H. Morgan COMMISSIONER

IN WITNESS WHEREOF, I, JAMES MATTHEWS, Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 1 day of June, 1994.

James Matthews
JAMES MATTHEWS
EXECUTIVE SECRETARY

DISSENT ______________________
BSC

DECISION NO. 58643

SERVICE LIST FOR: INTEGRATED RESOURCE PLANNING

DOCKET NO.: U-0000-93-052

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